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 Supplemental Wholesale Power Rate Case Initial Proposal

# FY 2002-2008
# LOOKBACK STUDY

February 2008

WP-07-E-BPA-44

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**FY 2002-2008**

**LOOKBACK STUDY**

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## 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 |
| COU | Consumer Owned Utility |
| 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 |
| LBLF | Lookback/Lookforward Model |
| LLH | Light Load Hour |
| LOLP | Loss of Load Probability |
| LRA | Load Reduction Agreement |
| 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 |
| MMBtu | 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 |
| 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 |
| NWEC | Northwest Energy Coalition |
| 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 |
| PS | Power Services (formerly Power Business Line) |
| 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 |
| TS | Transmission Services (formerly Transmission Business Line) |
| 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 |

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## LOOKBACK STUDY

**Overview of the Study**

The Lookback Study present BPA's response to the remand order of the United States Court of Appeals for the Ninth Circuit (Ninth Circuit or Court) concerning BPA's WP-02 rates. Three related opinions have placed BPA in the position of correcting past (fiscal years (FY) 2002-2006) and current (FY 2007-2008) errors in the allocation of costs included in BPA's wholesale power rates to certain customers. In *Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037, (9th Cir. 2007) (*Golden NW*), the Court held that BPA's WP¬02 power rates had improperly allocated the costs of the 2000 Residential Exchange Program Settlement Agreements (REP Settlement Agreements), as amended (REP settlements), to BPA's preference customers. Because the Court held that BPA's allocation of REP settlement costs in the WP-02 rates was improper, BPA knows that the allocation of such costs in the WP-07 rates is similarly flawed.

In addition, in *Golden NW*, the Court held that BPA's WP-02 fish and wildlife cost estimates, and by extension the rates set pursuant to those estimates, were not supported by substantial evidence. The Court indicated BPA had relied on outdated assumptions and had not appropriately considered information presented to it regarding its fish and wildlife costs. BPA's approach to addressing fish and wildlife costs for the WP-07 rates does not suffer the same flaws identified by the Court in the WP-02 rates. Nonetheless, BPA is taking steps to ensure that this WP-07 Supplemental Proposal rates for FY 2009 are based on the most recent projections of fish and wildlife costs that reflect the information available at the time of rate development.

In a companion case, the Court held that BPA's the REP Settlement Agreements with the IOUs were contrary to the Northwest Power Act. *Portland General Elec. Co. v. Bonneville Power*

*Admin.*, 501 F.3d 1009 (9th Cir. 2007) (*PGE*). Subsequent to the *Golden NW* and *PGE* decisions, the Court ruled on three petitions for review challenging related Load Reduction Agreements (LRAs) BPA executed with two IOUs during the energy crisis of 2000-2001. The Court dismissed two of the petitions for lack of jurisdiction and one petition as moot. The Court also reviewed challenges to amendments to the REP Settlement Agreements adopted in 2004. In *Public Utility Dist. No. 1 of Snohomish County, Wash. v. Bonneville Power Admin.*, 506 F.3d 1145 (9th Cir. 2007) (*Snohomish*), the Court remanded the amendments and a contract provision establishing a "Reduction of Risk" discount to BPA.

The Lookback Study presents BPA's proposal to reform its WP-02 and WP-07 rates to be consistent with the Court's direction. In doing so, BPA is proposing that the actual rates charged consumer-owned utilities (COUs) between October 1, 2001 and September 30, 2008 **not** be recalculated and revised billings issued. Rather, BPA proposes that the amount of costs overpaid to IOUs be identified and returned to preference customers through the various means explained in this Study.

The REP was established through section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839, et seq. Section 5(c) provides that

> Whenever a Pacific Northwest electric utility offers to sell electric power to the Administrator at the average system cost of that utility's resources in each year, the Administrator shall acquire by purchase such power and shall offer, in exchange, to sell an equivalent amount of electric power to such utility for resale to that utility's residential users within the region.

16 U.S.C. § 839c(c)(1). Further, section 7(b)(1) provides that

> The Administrator shall establish a rate or rates of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the Pacific Northwest, and loads of electric utilities under section 5(c).

16 U.S.C. § 839e(b)(1). This provision identifies that the rates to be paid by exchanging utilities for the power purchased from BPA be the same as those paid by preference customers. However, section 7(b)(3) provides that the rates paid by exchanging utilities may be modified by the effects of the rate protection provided to preference customers by section 7(b)(2). BPA identifies the rate applicable to purchases from BPA under the REP as the Priority Firm Power (PF) Exchange rate.

Section 5(c)(1) provides that the rates paid by BPA for the power purchased from exchanging utilities under the REP is their average system cost (ASC) developed according to a methodology established consistent with section 5(c)(7). BPA developed its current ASC Methodology in 1984. The ASC Methodology sets forth the procedures used to determine each utility's ASC.

The REP, although couched in terms of a purchase and sale of power between BPA and the exchanging utility, can be reduced to a paper transaction because the amount of power purchased by BPA is equal to the amount of power purchased by the exchanging utility. The transaction results in payments made at the difference between the utility's ASC and BPA's PF Exchange rate, multiplied by the eligible exchange load.

Therefore, in order to determine the amounts of REP payments to properly allocate to preference customers for the WP-02 and WP-07 rate periods, BPA must compute the ASCs and PF Exchange rates applicable to each period. The PF Exchange rate can be determined only after consideration of the section 7(b)(2) rate test. The Lookback Study sets forth BPA's proposed calculations of each of the factors used in establishing REP payment amounts that would have occurred in the absence of the REP settlements.

Once the proper REP payment amounts is determined for FY 2002-2008, a comparison with the amounts paid under the REP settlements can be used to determine the amount overpaid to the IOUs. The Study then lays out the mechanism for recovering these overpayments and returning them to COUs over time and starting in FY 2009.

**Organization**

The Lookback Study is divided into three parts following this introduction. These parts are: FY 2002-2006 Lookback; FY 2007-2008 Lookback; and Lookback Results. The FY 2002-2006 Lookback covers the period that the WP-02 rates were in effect. It sets forth BPA's calculations of an applicable PF Exchange rate that conform with section 7(b) of the Northwest Power Act and *Golden NW* as well as ASCs and loads that generally conform with the 1984 ASC Methodology.

The 2007-2008 Lookback covers the first two years that the WP-07 rates, BPA's current rates, have been in effect. It sets forth BPA's calculations of an applicable PF Exchange rate that conform with section 7(b) of the Northwest Power Act, as well as ASCs that generally conform with the 1984 ASC Methodology.

Finally, the Lookback Results part brings together the results of the first two parts and discusses the recovery and return of the amounts of overpayments to IOUs under the REP settlements. The PF Exchange rates and ASCs are applied to eligible residential and small farm loads to compute the proper REP amounts for each year that are then compared to the amounts paid to IOUs under the REP settlement. Other factors, such as the application of deemer balances accrued by IOUs when their ASCs were less than the PF Exchange rate and the amounts received by IOUs under LRAs, are included in the comparison through the application of a set of rules.

The results of these comparisons are the amounts overpaid to IOUs that need to be recovered and returned to PF customers. These overpayments to IOUs between October 2001 and September 2008 are called "Lookback Amounts." The Lookback Amounts are determined for each IOU by accumulating annual amounts. The Lookback Study also describes how BPA proposes to recover the Lookback Amounts from the IOUs and return them to preference customers.

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PART ONE: FY 2002-2006 LOOKBACK

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## 1. FY 2002-2006 INTRODUCTION

Part One of the Lookback Study (FY 2002-2006) presents BPA's proposal to reform the WP-02 rates to be consistent with the Court's direction. BPA is proposing that the Court's remand to BPA can be satisfied by computing the amounts of REP Settlement costs overpaid to IOUs and charged to preference customers. To calculate these amounts, BPA must determine the proper amounts to be allocated to PF preference rates. BPA proposes that the proper amounts can be calculated only after determining the appropriate PF Exchange rate for the period. Because the PF Exchange rate and ASCs determined in the WP-02 rate proceeding was so intertwined with assumptions regarding the REP Settlement Agreements, BPA proposes that the WP-02 PF Exchange rate must be recalculated.

Part One sets forth the determination of the properly constructed PF Exchange rate for FY 2002-2006 after removing the effects of the REP Settlement Agreements. To do so, BPA "looks back" to 2001 when the final 2002 rates were determined and excises the REP Settlement Agreement assumptions from the rate calculations and replaces them with Residential Purchase and Sale Agreements (RPSAs) that conform to an REP consistent with sections 5(c) and 7(b).

The WP-02 rate proposal was conducted in three phases. First, in May 2000, BPA published its WP-02 Final Proposal, that included a PF Exchange rate, and filed the proposal with the Federal Regulatory Energy Commission (FERC). Shortly thereafter, conditions arose that led BPA to conclude that the final rates were inadequate to assure cost recovery and BPA requested that FERC stay review of the WP-02 Final Proposal. BPA then developed and published an Amended Rate Proposal in December 2000. Immediately thereafter, as financial prospects continued to deteriorate, BPA and customers began discussions that led to a settlement of issues that was incorporated into the WP-02 Supplemental Rate Proposal that was published in

February 2001. This Supplemental Proposal added a set of three Cost Recovery Adjustment Clauses (CRACs) to the WP-02 Final Proposal rates and the revisions were adopted by the Administrator in June 2001 and submitted to FERC for review and confirmation. BPA did not perform the section 7(b)(2) rate test and the PF Exchange rate was not recalculated in the WP-02 Supplemental Proposal because, in part, the IOUs had signed the REP Settlement Agreements by this time and the CRACs adequately addressed REP-related cost recovery issues.

However, BPA has determined that absent the REP Settlement Agreements, the failure to redo the section 7(b)(2) rate test would have fatally compromised the June 2001 rate structure due to the impact of the changed conditions on the results of the rate test and the PF Exchange rate. Relying solely on CRACs when conditions had changed so radically would not have assured preference customers of the proper rate protection, nor would it have assured IOUs of the proper level of REP payments. Therefore, BPA has examined the major assumptions affecting the calculation of the PF Exchange rate at the time of the WP-02 Supplemental Proposal for the purpose of calculating a proper PF Exchange rate. The load forecast and revenue requirement were updated based on data available in the WP-02 Supplemental Proposal, as was the market price forecast. The market price forecast affected not only BPA rates, but ASC forecasts as well. Also, whereas an important issue regarding the 7(b)(2) rate test was mooted by conditions in the WP-02 Final Proposal, those conditions had changed by June 2001 so that the issue would have been decided at that time. Based on the record of the WP-02 proceeding, the Administrator has now decided that the Mid-Columbia resources included in the 7(b)(2)(D) resource stack were improperly included and those resources are now removed. These changed assumptions are then incorporated into BPA's rate model as it existed at the conclusion of the WP-02 Supplemental Proposal stage of the WP-02 rate proceeding.

The following sections set forth the changes to the rate models and the inputs used to recompute the PF Exchange rate for the FY 2002-2006 period. However, this newly-calculated

PF Exchange rate is necessary but not sufficient to fully incorporate the removal of the REP settlements from the rates charged.  The rates also included CRACs that changed rate levels throughout the rate period, and the REP settlements affected the CRAC results.  Therefore, the REP settlement impacts on the CRACs have also been removed through a simplified process described in this study.  The "reformed" CRACs are then applied to achieve the final PF Exchange rate used in this Lookback Study.

In addition to the PF Exchange rate, the ASCs for each IOU must be determined.  Because the REP Settlement Agreements had attempted to settle disputes regarding various aspects of the REP, ASCs were not filed during the 2002-2006 lookback period.  As a substitute, BPA has incorporated FERC Form 1 data into the ASC determination model in a manner consistent with the 1984 ASC Methodology and estimated the annual ASCs for each IOU for both ratesetting purposes (re-forecasts) and REP implementation purposes (backcasts).  These are also explained in this Lookback Study.

# 2. LOAD RESOURCE STUDY

## 2.1 Load Forecast FY 2002-2006

### 2.1.1 Public and Federal Agency Load Forecast FY 2002-2006

BPA has used the load obligation forecasts for the public body utilities, cooperative utilities, and the Federal agencies (together referred to as "Public Agencies") as presented in the 2002 Supplemental Proposal Final Study (WP-02-FS-BPA-09, page 2-8) for this Lookback Study.

### 2.1.2 DSI Load Forecast FY 2002-2006

The forecast of sales to the direct service industries (DSI) is unchanged from the WP-02 Final Proposal, which was used for the WP-02 Supplemental Proposal Final Study.

### 2.1.3 Load Forecast FY 2007-2010

The WP-02 Supplemental Proposal did not include a 7(b)(2) rate test. Therefore, no load obligation forecasts for FY 2007-2010 were required. The Lookback Study assumes the REP settlement agreements are replaced by an REP. Therefore load obligation forecasts for FY 2007-2010 are required for the 7(b)(2) rate test.

The load obligation forecasts for FY 2007-2010 were retrieved from BPA's Load and Resource Information System (LARIS) using a load obligation forecast consistent with that used in the 2002 Supplemental Proposal Final Study, WP-02-FS-BPA-09. These load obligation forecasts can be found in the WP-02 Supplemental Proposal Final Study Documentation, WP-02-FS-BPA-10. Table 1 displays the annual averages for FY 2002-2006 from the WP-02 Final Proposal and those used in this Lookback Study, which includes approximately 1,600 aMW of Slice load.

**Table 1**
**Comparison of Public and Federal Agency Sales Obligation Forecasts**
annual average megawatts

| | WP-02 Final Proposal | Lookback Study Forecast* |
|---|---|---|
| FY 2002 | 4,130 | 5,728 |
| FY 2003 | 4,221 | 5,776 |
| FY 2004 | 4,335 | 5,823 |
| FY 2005 | 4,414 | 5,870 |
| FY 2006 | 4,602 | 5,938 |
| 5-Year Average | 4,340 | 5,827 |

* (including about 1,600 aMW of Slice)

### 2.1.4 IOU Load Forecast

In the WP-02 Final Proposal, BPA assumed 1,000 aMW of sales to the IOUs as established in the REP Settlement Agreements. Absent the REP settlements there would have been no firm power sales to the IOUs at the RL rate.

## 2.2 Federal System Resources FY 2002-2006

The resources and contract purchase estimates for the Lookback Study are identical to the WP-02 Final Proposal, except for any updates to the Federal system augmentation purchase estimates. These updates were not performed in the Load Resource Study, rather these changes were incorporated in the Rate Analysis Model (RAM), described in this Study, Section 5.

## 2.3 Load Forecast FY 2007-2008

There were no changes to the load forecast from the WP-07 Final Proposal.

## 2.4 Federal System Resources FY 2002-2006

There were no changes to Federal System resources from the WP-07 Final Proposal.

# 3. REVENUE REQUIREMENT

## 3.1 Purpose of the Generation Revenue Requirement

The purpose of this section is to establish the level of revenues from wholesale power rates that, in retrospect, would have been necessary to recover, in accordance with sound business principles, the Federal Columbia River Power System (FCRPS) costs associated with the production, acquisition, marketing, and conservation of electric power assuming that BPA had recalculated base rates in the WP-02 Supplemental Proposal. The generation revenue requirement includes: recovery of the Federal investment in hydro generation, fish and wildlife and conservation costs; Federal agencies' operations and maintenance (O&M) expenses allocated to power; capitalized contract expenses associated with non-Federal power suppliers such as Energy Northwest (EN); other power purchase expenses, such as short-term power purchases; power marketing expenses; cost of transmission services necessary for the sale and delivery of FCRPS power; and all other generation-related costs incurred by the Administrator pursuant to law.

## 3.2 Spending Level Development

### 3.2.1 Development Process for Spending Levels in the WP-02 Rate Case

The development of spending levels reflected in the WP-02 Supplemental Proposal revenue requirement was largely driven by the Regional Cost Review (Cost Review), a review of FCRPS costs launched jointly, in September 1997, by BPA and the Northwest Power and Conservation Council (NPCC). The result of the Cost Review was a set of recommendations to reduce the costs of BPA's commercial operations and constrain the costs of its public benefit programs. The Cost Review was built on the earlier Comprehensive Regional Review (Comprehensive Review), which envisioned a dramatically shrinking role for BPA. Both the Comprehensive

Review and the Cost Review are described in the Final Revenue Requirement Study, WP-02-FS-BPA-02, Section 2.

### 3.2.2 Adjustments to Program Expenses Used in the WP-02 Rate Proceeding for the Lookback

The forecasts of program expenses used in the WP-02 Supplemental Proposal have not been changed for this proceeding. The program expense assumptions used in the WP-02 Final Proposal were the only complete set of program expense forecasts available during the WP-02 Supplemental Proposal proceeding.

### 3.2.3 Capital Funding

FCRPS capital investments include Corps, Reclamation, and BPA capital investments and third-party resource investments for which debt is secured by BPA (capitalized contracts). The WP-02 Final Proposal FCRPS capital outlay projections were $1,399 million for the FY 2002-2006 rate period. With the exception of the following items, these investment projects were not adjusted as part of the Lookback process.

Two capital investment assumptions important to the revenue requirement study and repayment study would have been updated if BPA had revised power base rates in the WP-02 Supplemental Proposal. These updates are reflected in this Supplemental Proposal. First, the WP-02 Supplemental Proposal did not include a forecast of capital spending for the Conservation Augmentation (ConAug) program. The program was created in 2000 to aid in meeting BPA's power augmentation needs. A forecast of ConAug capital investment, totaling $300 million for the FY 2002-2006 rate period, was available near the end of the WP-02 Supplemental Proposal process. If the revenue requirement study had been revised, that forecast would have been used in the determination of associated annual costs to replace the rough estimates of potential ConAug expenses that had been included in WP-02 rate development. Second, the plant-in-service forecast for the Columbia River Fish Mitigation (CRFM) project had changed by the end of the WP-02 Supplemental Proposal process and would have been used if the revenue requirement study had been revised. The new forecast lowered CRFM capital investment by approximately $225 million beginning in FY 2001 through the FY 2002-2006 rate period.

In addition, the WP-02 Final Proposal included projected investments for FY 2000. At the time of the WP-02 Supplemental Proposal, the actual investments for FY 2000 were known. In cases where the actual results for FY 2000 differed from the forecast, the forecasted investments and plant-in-service dates were modified to determine interest expense and depreciation/amortization expense.

## 3.3 Generation Revenue Requirement

For each year of a rate test period, BPA prepares two tables that reflect the process by which revenue requirements are determined. The Income Statement includes projections of Total Expenses, PNRR, and if necessary, a Minimum Required Net Revenues component. The Statement of Cash Flows shows the analysis used to determine Minimum Required Net Revenues and the cash available for risk mitigation. The table formats and line descriptions in this section are consistent with those used in the WP-02 Supplemental Proposal. They are not the same formats and descriptions used in the Supplemental Proposal.

The Income Statement (Table 3.1) displays the components of the annual revenue requirements, which include Total Operating Expenses (Line 16), Net Interest Expense (Line 24), Minimum Required Net Revenues (Line 26), and Planned Net Revenues for Risk (Line 27). The sum of these four major components is the Total Revenue Requirement (Line 29).

The amounts shown in Total Operating Expenses and Net Interest Expense are primarily established outside the ratesetting process. The Minimum Required Net Revenues (Line 26) result from an analysis of the Statement of Cash Flow (Table 3.2). Minimum Required Net Revenues may be necessary to ensure that revenue requirements are sufficient to cover all cash requirements, including annual amortization of the Federal investment as determined in the power repayment studies and any other cash requirements such as payment of irrigation assistance.

The Statement of Cash Flow analyzes annual cash inflows and outflows. Cash provided by Current Operations (Line 7), driven by the Non-Cash Expenses shown in Lines 4, 5, and 6 must be sufficient to compensate for the difference between Cash Used for Capital Investments (Line 13) and Cash from Treasury Borrowing and Appropriations (Line 20). If cash provided by Current Operations are not sufficient, Minimum Required Net Revenues must be included in revenue requirements to accommodate the shortfall, yielding at least zero annual Increase in Cash (Line 21). The Minimum Required Net Revenues shown on the Statement of Cash Flows (Line 2) is then incorporated in the Income Statement (Line 26).

### 3.3.1 Income Statement

Below is a line-by-line description of the components in the Income Statement (Table 3.1). Documentation for Revenue Requirement Study, WP-02-FS-BPA-02B, Volume 1 provides additional information on the development and use of the data contained in the tables. Additional information on the development of data used in this Lookback process can be found in the Lookback Documentation, WP-07-E-BPA-44A, Section 3.

**O&M (Line 2).** O&M represents FCRPS system O&M expenses incurred by the COE, Reclamation, U.S. Fish and Wildlife Service (USFWS), and BPA. Specific BPA O&M

expenses include generation oversight, power scheduling, (including upstream benefits), power marketing, Civil Service Retirement System pension expense, inter-business line expenses, administrative and support services, GTAs, and the costs of the NPPC. This line also includes payments to the Confederated Tribes of the Colville Reservation as called for under the Colville Settlement Act.

**Short-Term Power Purchases (Line 4).** Short-term purchases of power and off-system storage services are made to provide operational flexibility, displace higher cost purchases, and augment the system output to serve Subscription loads. System augmentation purchases are made to achieve load/resource balance on an annual basis. Balancing power purchases are made to achieve load/resource balance on an hourly, daily, and monthly basis. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Section 4; and Final WPRDS, WP-02-FS-BPA-05.

**Long-Term Power Purchases (Line 5).** Long-term power purchases are acquisitions of cost-effective resources intended to meet BPA's load obligations. These long-term commitments include the Idaho Falls and Cowlitz Falls hydroelectric projects, the billing credits and competitive acquisitions programs, and renewable resources such as wind and geothermal resource development. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Section 4.

**Trojan (Line 6).** Through net-billing arrangements, BPA has acquired Eugene Water and Electric Board's (EWEB) 30 percent ownership share of the now-terminated Trojan Nuclear Project. BPA's cost includes EWEB's share of Trojan phase-down, decommissioning costs, EWEB's debt service, and other Trojan-related costs. EWEB's other Trojan-related costs include contributions in lieu of taxes and EWEB's direct costs.

*See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Sections 4 and 10.

**WNP-1, -2, and –3 (Lines 7, 8 and 9).** Through project and net-billing agreements with Energy Northwest and BPA preference customer participants, and through exchange agreements with IOUs, BPA has acquired 100 percent of the capability of WNP-1 and -2 (now known as Columbia Generating Station, CGS) and 70 percent of the capability of WNP-3. Under a settlement agreement, BPA has certain rights to and obligations for the IOUs' 30 percent share of WNP-3.

BPA is obligated to fund all cash requirements associated with its share of these projects. These cash requirements include debt service and legal costs for WNP-1; debt service, operating, decommissioning, and capital costs for WNP-2; and debt service, 70 percent of preservation, and IOU settlement costs for WNP-3. IOU settlement costs for WNP-3 include the remaining 30 percent of preservation costs for that project.

Debt service costs include interest on outstanding Energy Northwest bonds, retirement of bonds according to schedules in each bond issue, and a reserve and contingency amount equal to 10 percent of the annual interest and retirement of bonds, less investment income on various accounts (Bond Fund Reserve Account, Bond Fund Interest Account, Reserve and Contingency Fund, Bond Fund Principal Account, and Revenue Fund), and transfer of any prior year's surplus reserve and contingency. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Sections 4 and 10.

**Residential Exchange Program (Line 10).** BPA's rate development methodology is based on the gross costs of the program, that is, the utilities' ASCs times their exchangeable loads.

**BPA Fish and Wildlife O&M (Line 11).** BPA funds projects designed to accomplish measures in the NPCC's Columbia River Basin Fish and Wildlife Program and the 1995 National Marine Fisheries Service (NMFS) Biological Opinion, and to be consistent with the fish cost stabilization agreement. This line item includes the expense portion of BPA's Fish and Wildlife "direct" Program, including staff costs and operating expenses of fish and wildlife activities. These activities include measures to implement the NPCC's Fish and Wildlife Program and Biological Opinions issued by the NMFS and the USFWS. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Sections 4 and 13.

**Amortization of Fish and Wildlife Investment (Line 12).** Amortization of Fish and Wildlife is the annual expense associated with the write-off of BPA capital investments in BPA's Fish and Wildlife Program. The annual write-off is calculated using the straight-line method of depreciation over an expected average life of 15 years. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Sections 4 and 5.

**Conservation (Line 13).** The Northwest Power Act requires BPA to treat cost-effective conservation as an electric power resource in planning to meet the Administrator's obligations to serve loads. The competitive market situation is driving the need for alternatives to traditional approaches to developing conservation resources. BPA was transitioning from centralized BPA-funded programs to new customer-driven approaches. The costs shown here reflect BPA's participation with other regional entities supporting marketing transformation and development activities, as well as facilitating activities that meet the needs of customers and create business opportunities for the private sector.

*See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Sections 4 and 10.

**Amortization of Conservation Investment (Line 14).** Amortization of Conservation is the annual expense associated with the write-off of BPA's investments in energy conservation measures. The annual conservation write-off is calculated using the straight-line method of depreciation over an expected life of 20 years. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Sections 4 and 5. This line also includes the amortization of ConAug capital investments added as a part of the Lookback process. *See* Lookback Documentation, WP-07-E-BPA-44A, Section 3.

**Federal Projects Depreciation (Line 15).** Depreciation is the annual capital recovery expense associated with FCRPS plant-in-service. Reclamation and COE (including lower Snake River Fish and Wildlife Compensation Plan) plant, including assets for fish and wildlife recovery, is depreciated by the straight-line method of calculation, using the average service life of each project. Capital equipment (office furniture and fixtures and data processing hardware and software) is also depreciated by the straight-line method using the average service life for the categories of capital investment. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Sections 4 and 5. This line also includes adjustments to amortization associated with the use of a revised CRFM forecast. *See* Lookback Documentation, WP-07-E-BPA-44A, Section 3.

**Total Operating Expenses (Line 16).** Total Operating Expenses is the sum of the above expenses (Lines 2 through 15).

**Interest on Appropriated Funds (Line 19).** Interest on Appropriated Funds includes interest on BPA, COE, and Reclamation appropriations as determined in the generation repayment studies. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Sections 4, 6, and 9. This line also includes adjustments to interest expense associated with the use of a revised CRFM forecast. *See* Lookback Documentation, WP-07-E-BPA-44A, Section 3.

**Interest on Long-Term Debt (Line 20).** Interest on long-term debt includes interest on bonds that BPA issues to the U.S. Treasury to fund investments in capital equipment, conservation, fish and wildlife, and to fund Reclamation and COE investments under the Energy Policy Act of 1992 (EPA-92) (P.L. No. 102-486, 1992 U.S. Code Cong. & Admin. News, 106 Stat. 2776). Such interest expense is determined in the generation repayment studies. Any payments of premiums for bonds projected to be amortized are included in this line. Also included is an interest income credit calculated in the generation repayment studies on funds to be collected during each year for payments of Federal interest and amortization at the end of the fiscal year. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Sections 4, 6, and 9. This line also includes an increase to interest expense associated with the inclusion of ConAug investments. *See* Lookback Documentation, WP-07-E-BPA-44A, Section 3.

**Interest Credit on Cash Reserves (Line 21).** An interest income credit is also computed on the projected year-end cash balance in the BPA fund attributable to the Power function that carries over into the next year. It is credited against bond interest. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Section 6.

**Capitalization Adjustment (Line 22).** Implementation of the Refinancing Act entailed a change in capitalization on BPA's financial statements. Outstanding appropriations were reduced as a result of the refinancing by $2,142 million in the generation function. The reduction is recognized annually over the remaining repayment period of the refinanced appropriations. The annual recognition of this adjustment is based on the increase in annual interest expense resulting from implementation of the Refinancing Act, as shown in repayment studies for the year of the refinancing transaction (1997). The capitalization adjustment is included on the income statement as a non-cash, contra-expense. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Section 8.

**Allowance for Funds Used During Construction (AFUDC) (Line 23).** AFUDC is a credit against interest costs on long-term debt (Line 20). This reduction to interest costs reflects an estimate of interest on the funds used during the construction period of facilities that have yet to be placed in service. AFUDC is capitalized along with other construction costs and is recovered through rates over the expected service life of the related plant as part of the depreciation expense after the facilities are placed in service. AFUDC, which is calculated outside the generation repayment studies, is associated with the COE and Reclamation capital investments direct-funded by BPA. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Section 4.

**Net Interest Expense (Line 24).** Net Interest Expense is computed as the sum of Interest on Appropriated Funds (Line 19), Interest on Long-Term (Line 20), Interest Credit on Cash Reserves (Line 21), capitalization adjustment (Line 22), and AFUDC (Line 23).

**Total Expense (Line 25).** Total Expenses are the sum of Total Operating Expenses (Line 16) and Net Interest Expense (Line 24).

**Minimum Required Net Revenues (Line 26).** Minimum Required Net Revenues, an input from Line 2 of the Statement of Cash Flows (Table 3.2), may be necessary to cover cash requirements in excess of accrued expenses. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Section 1.

**Planned Net Revenues for Risk (Line 27).** Planned Net Revenues for Risk are the amount of net revenues to be included in rates for financial risk mitigation. Planned net revenues for risk of $98 million per year (in addition to starting reserves, the cash flow when non-cash expenses exceed cash payments, the CRAC and other risk mitigation tools) are available to mitigate risk in FY 2002-2006.

**Total Planned Net Revenues (Line 28).** Total Planned Net Revenues is the sum of Minimum Required Net Revenues (Line 26) and Planned Net Revenues for Risk (Line 27).

**Total Revenue Requirement (Line 29).** Total Revenue Requirement is the sum of Total Expenses (Line 25) and Total Planned Net Revenues (Line 28).

### 3.3.2 Statement of Cash Flows

Below is a line-by-line description of each of the components in the Statement of Cash Flows (Table 3.2). Volumes 1 and 2 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A and WP-02-FS-BPA-02B, provide additional information related to the use and development of the data contained in table.

**Minimum Required Net Revenues (Line 2).** Determination of this line is a result of annual cash inflows and outflows shown on the Statement of Cash Flows. Minimum Required Net Revenues may be necessary so that the cash provided from operations will be sufficient to cover the planned amortization and irrigation assistance payments (the difference between Lines 13 and 20) without causing the Annual Increase (Decrease) in Cash (Line 21) to be negative. The Minimum Required Net Revenues amount determined in the Statement of Cash Flows is incorporated in the Income Statement (Line 26).

**Federal Projects Depreciation (Line 4).** Depreciation is from the Income Statement (Table 3.1, Line 15). It is included in computing Cash Provided By Operations (Line 8) because it is a non-cash expense of the FCRPS.

**Amortization of Conservation/Fish and Wildlife Investment (Line 5).** Amortization of Conservation and Fish and Wildlife Investment is from the Income Statement (Table 3.1, Lines 12 and 14). Similar to Depreciation (Line 4), it is a non-cash expense.

**Capitalization Adjustment (Line 6).** Capitalization Adjustment is from the Income Statement (Table 3.1, Line 22). It is a non-cash (contra) expense. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Section 8.

**Cash Provided By Current Operations (Line 7).** Cash Provided By Current Operations, the sum of Lines 2, 4, 5, and 6 is available for the year to satisfy cash requirements.

**Investment in Utility Plant (Line 10).** Investment in Utility Plant represents the annual increase in additions to plant-in-service for COE, Reclamation, and BPA including construction work-in-progress funded by bonds. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Section 5.

**Investment in Conservation (Line 11).** Investment in Conservation represents the annual increase in capital expenditures associated with Conservation programs. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Section 4.

**Investment in Fish and Wildlife (Line 12).** Investment in Fish and Wildlife represents the annual increase in BPA's capital expenditures to fund projects designed to comply with the NPCC's Columbia River Basin Fish and Wildlife Program and Biological Opinions issued by NMFS and USFWS. These amounts are consistent with the Principles. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Sections 5 and 13.

**Cash Used for Capital Investments (Line 13).** Cash Used for Capital Investments is the sum of Lines 10, 11, and 12.

**Increase in Long-Term Debt (Line 15).** Increase in Long-Term Debt reflects the new bonds issued by BPA to the U.S. Treasury to fund capital equipment, conservation, and fish and wildlife capital programs and to direct-fund Reclamation and COE investments under the EPA-92. Also included in this amount are any notes issued to the U.S. Treasury. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Section 7.

**Repayment of Long-Term Debt (Line 16).** Repayment of Long-Term Debt is BPA's planned repayment of outstanding bonds issued by BPA to the U.S. Treasury as determined in the generation repayment studies. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1.

**Increase in Congressional Capital Appropriations (Line 17).** Increase in Congressional Capital Appropriations represents Congressional appropriations projected to be received during the year for COE and Reclamation capital projects. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Section 5.

**Repayment of Capital Appropriations (Line 18).** Repayment of Capital Appropriations represents projected amortization of outstanding COE and Reclamation appropriations as determined in the generation repayment studies. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02B, Volume 2.

**Payment of Irrigation Assistance (Line 19).** Payment of Irrigation Assistance represents the payment of appropriated capital construction costs of Reclamation irrigation facilities that have been determined to be beyond the ability of the irrigators to pay and allocated to generation revenues for repayment. *See* Final Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, Volume 1, Section 10.

**Cash From Treasury Borrowing and Appropriations (Line 20).** Cash from Treasury Borrowing and Appropriations is the sum of Lines 15 through 19. This is the net cash flow resulting from increases in cash from new long-term debt and capital appropriations and decreases in cash from repayment of long-term debt and capital appropriations.

**Annual Increase (Decrease) in Cash (Line 21).** Annual Increase (Decrease) in Cash is the sum of Lines 7, 13, and 20 and reflects the annual net cash flow from current operations and investing and financing activities. Revenue requirements are set to meet all projected annual cash flow requirements, as included on the Statement of Cash Flows. A decrease shown in this line would indicate that annual revenues would be insufficient to cover the year's cash requirements. In such cases, Minimum Required Net Revenues are included to offset such decrease. *See* discussion above of Minimum Required Net Revenues (Line 2).

**Planned Net Revenues for Risk (Line 22).** Planned Net Revenues for Risk reflects the amounts included in revenue requirements to meet BPA's risk mitigation objectives (from Table 3.1, Line 27).

**Total Annual Increase (Decrease) in Cash (Line 23).** Total Annual Increase (Decrease) in Cash is the sum of Lines 21 and 22. It is the total annual cash that is projected to be available to add to BPA's cash reserves.

### 3.3.3 Revenue Test

In a typical rate proceeding, the revenue requirement study would demonstrate the continuing adequacy of existing rates must be tested annually, consistent with RA 6120.2. The revenue tests determine whether the revenues projected from current rates and from proposed rates will meet cost recovery requirements as well as the U.S. Treasury payment probability risk goal for the rate period. Since we are not recalculating rates for retroactive application, these tests of adequacy are not necessary.

# Table 3.1

**GENERATION REVENUE REQUIREMENT**
**INCOME STATEMENT**
**($000s)**

| | | A FY 2002 | B FY 2003 | C FY 2004 | D FY 2005 | E FY 2006 |
|---|---|---|---|---|---|---|
| 1 | OPERATING EXPENSES: | | | | | |
| 2 | OPERATION & MAINTENANCE | 469,614 | 453,220 | 446,510 | 441,161 | 438,260 |
| 3 | PURCHASE AND EXCHANGE POWER- | | | | | |
| 4 | SHORT-TERM POWER PURCHASES | 931,218 | 835,152 | 838,667 | 890,696 | 843,768 |
| 5 | LONG-TERM POWER PURCHASES | 65,904 | 66,159 | 66,450 | 66,977 | 67,414 |
| 6 | TROJAN | 19,547 | 14,154 | 12,564 | 12,589 | 12,609 |
| 7 | WNP NO. 1 | 178,104 | 168,240 | 175,007 | 168,294 | 180,376 |
| 8 | WNP NO. 2 | 351,536 | 408,804 | 404,348 | 361,649 | 391,800 |
| 9 | WNP NO. 3 | 156,806 | 156,162 | 152,401 | 152,649 | 151,006 |
| 10 | RESIDENTIAL EXCHANGE PROGRAM | 0 | 0 | 0 | 0 | 0 |
| 11 | BPA FISH & WILDLIFE O&M | 131,700 | 138,000 | 140,100 | 142,900 | 144,400 |
| 12 | AMORTIZATION OF BPA FISH & WILDLIFE INVESTMENT | 18,899 | 20,969 | 22,864 | 24,521 | 25,533 |
| 13 | CONSERVATION | 34,929 | 33,340 | 33,640 | 34,040 | 34,340 |
| 14 | AMORTIZATION OF BPA CONSERVATION INVESTMENT | 61,163 | 60,126 | 58,108 | 64,161 | 73,650 |
| 15 | FEDERAL PROJECTS DEPRECIATION | 96,328 | 98,991 | 100,364 | 103,207 | 105,731 |
| 16 | TOTAL OPERATING EXPENSES | 2,515,746 | 2,453,316 | 2,451,023 | 2,462,844 | 2,468,886 |
| 17 | INTEREST EXPENSE: | | | | | |
| 18 | INTEREST ON FEDERAL INVESTMENT- | | | | | |
| 19 | ON APPROPRIATED FUNDS | 240,719 | 242,176 | 247,781 | 255,551 | 255,779 |
| 20 | ON LONG-TERM DEBT | 64,034 | 70,273 | 78,934 | 88,175 | 96,674 |
| 21 | INTEREST CREDIT ON CASH RESERVES | (61,063) | (67,549) | (75,054) | (79,878) | (84,818) |
| 22 | CAPITALIZATION ADJUSTMENT | (47,738) | (47,528) | (47,875) | (44,790) | (44,790) |
| 23 | ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION | (2,992) | (2,890) | (2,050) | (2,056) | (2,044) |
| 24 | NET INTEREST EXPENSE | 192,960 | 194,482 | 201,736 | 217,002 | 220,801 |
| 25 | TOTAL EXPENSES | 2,708,706 | 2,647,798 | 2,652,759 | 2,679,846 | 2,689,687 |
| 26 | MINIMUM REQUIRED NET REVENUES 1/ | 0 | 0 | 0 | 998 | 0 |
| 27 | PLANNED NET REVENUES FOR RISK | 98,000 | 98,000 | 98,000 | 98,000 | 98,000 |
| 28 | TOTAL PLANNED NET REVENUES (26+27) | 98,000 | 98,000 | 98,000 | 98,998 | 98,000 |
| **29** | **TOTAL REVENUE REQUIREMENT** | **2,806,706** | **2,745,798** | **2,750,759** | **2,778,844** | **2,787,687** |

1/ SEE NOTE ON CASH FLOW TABLE.

## Table 3.2

**GENERATION REVENUE REQUIREMENT**
**STATEMENT OF CASH FLOWS**
**($000s)**

| | | A FY 2002 | B FY 2003 | C FY 2004 | D FY 2005 | E FY 2006 |
|---|---|---|---|---|---|---|
| 1 | CASH FROM CURRENT OPERATIONS: | | | | | |
| 2 | MINIMUM REQUIRED NET REVENUES 1/ | 0 | 0 | 0 | 998 | 0 |
| 3 | EXPENSES NOT REQUIRING CASH: | | | | | |
| 4 | FEDERAL PROJECTS DEPRECIATION | 96,328 | 98,991 | 100,364 | 103,207 | 105,731 |
| 5 | AMORTIZATION OF CONSERVATION/F&W INVESTMENT | 80,062 | 81,095 | 80,972 | 88,682 | 99,183 |
| 6 | CAPITALIZATION ADJUSTMENT | (47,738) | (47,528) | (47,875) | (44,790) | (44,790) |
| 7 | CASH PROVIDED BY CURRENT OPERATIONS | 128,652 | 132,558 | 133,461 | 148,097 | 160,124 |
| 8 | CASH USED FOR CAPITAL INVESTMENTS: | | | | | |
| 9 | INVESTMENT IN: | | | | | |
| 10 | UTILITY PLANT | (228,000) | (168,700) | (297,500) | (185,525) | (220,225) |
| 11 | CONSERVATION | 0 | 0 | 0 | 0 | 0 |
| 12 | FISH & WILDLIFE | (34,732) | (38,317) | (35,825) | (33,988) | (34,182) |
| 13 | CASH USED FOR CAPITAL INVESTMENTS | (262,732) | (207,017) | (333,325) | (219,513) | (254,407) |
| 14 | CASH FROM TREASURY BORROWING AND APPROPRIATIONS: | | | | | |
| 15 | INCREASE IN LONG-TERM DEBT | 127,032 | 125,917 | 98,425 | 97,013 | 97,207 |
| 16 | REPAYMENT OF LONG-TERM DEBT | (66,000) | (25,622) | (27,400) | (30,757) | 0 |
| 17 | INCREASE IN CONGRESSIONAL CAPITAL APPROPRIATIONS | 135,700 | 81,100 | 234,900 | 122,500 | 157,200 |
| 18 | REPAYMENT OF CAPITAL APPROPRIATIONS | (41,401) | (47,362) | (64,885) | (117,340) | (128,476) |
| 19 | PAYMENT OF IRRIGATION ASSISTANCE | 0 | 0 | (739) | 0 | 0 |
| 20 | CASH FROM TREASURY BORROWING AND APPROPRIATIONS | 155,331 | 134,033 | 240,301 | 71,416 | 125,931 |
| 21 | ANNUAL INCREASE (DECREASE) IN CASH | 21,251 | 59,574 | 40,437 | 0 | 31,648 |
| 22 | PLANNED NET REVENUES FOR RISK | 98,000 | 98,000 | 98,000 | 98,000 | 98,000 |
| 23 | TOTAL ANNUAL INCREASE (DECREASE) IN CASH | 119,251 | 157,574 | 138,437 | 98,000 | 129,648 |

1/ Line 21 must be greater than or equal to zero, otherwise net revenues will be added so that there are no negative cash flows for the year.

# 4. MARKET PRICE FORECAST

## 4.1 Market Price Forecast for FY 2002-2006

BPA is not proposing any changes to the market price forecast from the WP-02 Supplemental Proposal which was contained in the 2002 Supplemental Proposal Final Study, WP-02-FS-BPA-09. The results of this market price forecast will be used in the Lookback and are represented in Table 4.1:

**Table 4.1**
**Flat Annual Market Price Forecast**
($/MWh)

| Year | Price |
|---|---|
| FY 2002 | 148.00 |
| FY 2003 | 63.00 |
| FY 2004 | 45.96 |
| FY 2005 | 49.51 |
| FY 2006 | 49.07 |

For more information, *see* Conger, *et al.*, WP-07-E-BPA-56.

## 4.2 Market Price Forecast for FY 2007-2008

BPA is not proposing any changes to the Market Price Forecast Study, WP-07-FS-BPA-03, or Market Price Forecast Study Documentation, WP-07-FS-BPA-03A, published in the WP-07 Final Proposal.

# 5. WHOLESALE POWER RATE DEVELOPMENT STUDY, FY 2002-2006

## 5.1 Revised Forecasts of Average System Costs and Loads for FY 2002-2006

BPA made only one set of changes to the data inputs used in the WP-02 Final Proposal to revise the IOU ASC forecasts for the Lookback Study. These data changes updated the forward flat-block price forecasts, which were available from broker quotes in 2001. *See* Lookback Market Price Forecast, Section 4. The forecast available in June 2001 for flat-block purchased power prices was 148 mills/kWh in 2002, declining to 63.00, 45.92, 49.46, and 49.02 mills/kWh for the following four years, respectively. For the years 2007 through 2010, a 2.5 percent annual growth rate to the 2006 price was assumed. A transmission adder of 2.63 mills/kWh, unchanged from the adder used in the WP-02 Final Proposal, was added to all years of the price forecast. The Excel-based ASC Forecast Model used in the WP-02 Final Proposal was updated with the revised market price forecasts.

Also changed was an important assumption in the WP-02 Final Proposal regarding "in lieu" transactions, whereby BPA acquires power from a cheaper resource in lieu of acquiring power from the exchanging utility at its ASC. In the WP-02 Final Proposal, BPA assumed that it would in lieu 50 percent of the REP loads of Puget Sound Energy, Portland General Electric, and PacifiCorp's southern Idaho jurisdiction of its Utah Power (now Rocky Mountain Power) Division. Such transactions would have meant that BPA could buy actual power from another source at a price less than an exchanging utility's ASC, and could sell real power to the utility, effectively saving the difference between the ASC and the lower-cost power. As noted above, by June 2001, the forecast market quotes were showing prices significantly higher than forecast ASCs. Continuing to assume then that BPA would serve 50 percent (or any) of the exchanging utilities' loads with an in lieu purchase at the market price was therefore no longer reasonable. BPA is proposing no in lieu transactions for this Lookback Study.

Documentation Table 5.1.1 summarizes IOU ASC determinations from the WP-02 Final Proposal. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.1.1. This table also includes annual load-weighted ASCs.

Documentation Table 5.1.2 summarizes reforecast ASCs for NorthWestern Energy, PacifiCorp (both divisions), Portland General Electric and Puget Sound Energy, which were determined for this Lookback Study using the ASC Forecast model. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.1.2. ASC forecasts for Avista and Idaho Power were not based on the ASC Forecast model because base data for these utilities dated to the mid-1980s. Instead, estimated ASCs from the WP-02 Final Proposal are escalated as follows. Load-weighted reforecast ASCs are compared with the load-weighted results from Table 5.1.1, and show an increase in FY 2002 of 43.6 percent. This increase, and all subsequent annual increases, is used as a multiplier to determine reforecast ASCs for Avista and Idaho Power. For example, Avista's WP-02 Final Proposal ASC was estimated to be 29.25 mills/kWh. Its revised ASC forecast for 2002 is calculated as 29.25 × 1.436 = 42.00 mills/kWh. Avista and Idaho Power reforecast ASCs are shown in the Lookback Documentation, Table 5.1.2.

A side by side comparison by year and company of WP-02 Final Proposal ASCs and the reforecast ASCs is found in the Lookback Documentation, Table 5.1.3.

Documentation Table 5.1.4 shows model inputs and outputs for Northwestern, PacifiCorp (separate by division), Portland General Electric, and Puget Sound Energy.

## 5.2 FY 2002-2006 Lookback Cost Allocation and Rate Design Implementation

### 5.2.1 Ratemaking Sequence

The base rate ratemaking sequence used in the FY 2002-2006 Lookback is the same as was used in the WP-02 WPRDS except that the Subscription Strategy section is no longer necessary. The FY 2002-2006 Lookback ratemaking includes a Cost of Service Analysis (COSA) and a series of Rate Design Step adjustments using the same set of RAM2002 models used in the WP-02 Final Proposal. These models provide a forecast of base rates for the FY 2002-2006 time period. In addition, a new Post-Processor model has been developed for this Supplemental Proposal to determine if a CRAC adjustment to base rates would have been required to recover BPA's power costs in that time period.

Although the COSA procedures and Rate Design Step adjustments that made up BPA's ratemaking in the WP-02 Final Proposal are used in this Lookback analysis for FY 2002-2006, much of the data used in the current calculations are different than those used for the WP-02 Final Proposal. BPA is using ratemaking information that was available in and around the spring of 2001 in this Lookback analysis. A summary of the data differences is included as an appendix to this study. For a more detailed discussion of the data differences, *see* Brodie *et al.*, WP-07-E-BPA-58.

The COSA assigns responsibility for BPA's revenue requirement to the various classes of service in accordance with generally accepted ratemaking principles and in compliance with statutory directives governing BPA's ratemaking. The Rate Design Step adjustments to the allocated costs in the COSA are necessary to assure that BPA recovers its test period costs while maintaining the statutory-based relationship between the rates paid by the different rate pools and to implement particular statutory rate directives of the Northwest Power Act.

### 5.2.2 Cost of Service Analysis (COSA)

The COSA allocates the test period generation revenue requirements that are determined in the Revenue Requirement Study, Section 3, to BPA's customer classes. The COSA apportions or "allocates" the test period generation revenue requirements among classes of service based on the principle of cost causation. The relative use of resources, services, or facilities among customer classes is identified, and costs generally are allocated to customer classes in proportion to each class's use. Cost allocation also is based on the priorities of service from resource pools to rate pools provided in section 7 of the Northwest Power Act.

Four major ratemaking steps were completed in the process of determining BPA's total cost of service: (1) *functionalization* of costs between generation and transmission; (2) *segmentation* of costs of BPA's transmission system (not applicable in a power rate case); (3) *classification* of costs between demand, energy, and load variance; and (4) *allocation* of costs to classes of service.

In this FY 2002-2006 portion of the Lookback, BPA is determining what the power rates charged by BPA would have been absent the IOU REP Settlement Agreements. Functionalization of costs between generation and transmission was performed in conjunction with the development of BPA's total revenue requirements and only those costs associated with the Power function are included in BPA's power rates. The one exception is that the gross exchange resource costs are functionalized so that only the power portion is subject to the Rate Design Steps, and the transmission portion is then added back in after the Rate Design Steps are completed.
The remaining steps to determine BPA's cost of service for wholesale power – classification and allocation of costs – are performed in the COSA. *See* Lookback Documentation, WP-07-E-BPA-44A, Section 5.2.3.

### 5.2.3 Revenue Requirement

The Revenue Requirement Study, Section 3, is based on revenue and cost estimates for the five-year test period, FY 2002-2006. The generation revenue requirements from the Revenue Requirement Study are adjusted in the COSA for projected balancing purchase power costs, system augmentation costs, and the functionalization and classification of REP costs. *See* Section 5.2.3.1.1. For the five test years, the total adjusted generation revenue requirement is $17.773 billion. Adjusted annual functionalized revenue requirements used for rate calculations are shown in the Lookback Documentation, WP-07-E-BPA-44A, Tables 5.2.3.1 through 5.2.3.5, (COSA 06 FY 02 through COSA 06 FY 06). Total adjusted functionalized revenue requirements for the five-year period are shown in the Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.3.7, (COSA 08).

#### 5.2.3.1 Functionalized Revenue Requirement

Power rates are set to recover only generation costs and transmission costs associated with the Power function. Transmission rates were set in a separate rate case and were not affected by the REP settlements. The COSA uses revenue requirement for the generation component of the FCRPS. *See* Section 3.

#### 5.2.3.2 Power Purchases in the COSA

Three categories of purchased power are shown in the COSA: (1) purchased power; (2) balancing power purchases; and (3) system augmentation.

##### 5.2.3.2.1 Purchased Power

The purchased power costs reflect the acquisition of power through renewable energy, wind, geothermal, and competitive acquisition programs less the costs associated with the Idaho Falls and Cowlitz projects. Costs of purchased power from contracts from the early 1990s are included in the NR resource pool. *See* Lookback Documentation, WP-07-E-BPA-44A, Tables 5.2.3.1 through 5.2.3.5, (COSA 06 FY 2002 through COSA 06 FY 2006). Purchased power costs are unchanged from the WP-02 Final Proposal.

#### 5.2.3.2.2 Balancing Power Purchases

Included in the costs of balancing power purchases are the costs of power purchases and storage required to meet firm deficits on a daily and monthly basis. Projected balancing power purchases are needed to serve firm loads at the margin in months other than the spring fish migration period. The expense estimate for balancing power purchases included in the revenue requirements is adjusted in the COSA as a result of Risk Analysis Model (RiskMod) modeling to reflect projected operation of the FCRPS. For this Lookback, the cost of balancing power purchases was not changed from the WP-02 Final Proposal. *See* Lookback Documentation, WP-02-FS-BPA-05A, Section 3.4. Costs of balancing power purchases are characterized as FBS replacements and as such are included in and allocated as FBS costs. *See* Lookback Documentation, WP-07-E-BPA-44A, Tables 5.2.3.1 through 5.2.3.5, (COSA 06 FY 2002 through COSA 06 FY 2006).

#### 5.2.3.2.3 System Augmentation

BPA is also proposing to acquire resources beyond the inventory represented by the FBS and new resources. These acquisitions are defined as system augmentation costs in the COSA and are used to meet customer firm power loads in excess of firm Federal resources on an annual basis. System augmentation purchases are characterized as FBS replacements. The Federal system will be augmented using both long- and short-term power purchase contracts. System augmentation costs are shown in Lookback Documentation, WP-07-E-BPA-44A, Tables 5.2.3.1 through 5.2.3.5, and 5.2.3.7, (COSA 06) and (COSA 08). The amount and cost of system augmentation have been modified to be consistent with load and market price changes for the Lookback.

#### 5.2.3.2.4 Adjustments to Gross Residential Exchange Costs

BPA's revenue requirement includes the gross cost of the REP, which can be affected by the PF rate. In the beginning of the rate development process, REP costs are projected using an estimate of the PF rate for the test period. These costs are included in the functionalized revenue requirements. If the ultimate PF rate differs from the estimated rate, the REP costs are recalculated. The PF rate is then recalculated based on the revised REP costs. This iterative process stops when the PF rate does not change from the previous iteration. This adjustment of the gross REP costs is necessary because the PF rate level can influence the level of the Residential Exchange costs included in the COSA. *See* Lookback Documentation, WP-07-E-BPA-44A, Tables 5.2.3.1 through 5.2.3.5, (COSA 06 FY 2002 through COSA 06 FY 2006).

### 5.2.4 Functionalization and Classification of Residential Exchange Program Costs

In the COSA, the gross REP cost is based on exchanging utilities' ASCs and the amount of their exchangeable loads. ASCs include the cost of power, transmission, and unbundled services associated with serving the exchanging utility's exchangeable load. The rate design adjustments follow the COSA in the WPRDS and use the results of the COSA performed on that portion of the revenue requirement classified to energy. Consequently, the REP cost that comes into the COSA with energy costs, demand costs, transmission costs, and unbundled services costs included, must be functionalized to generation and then classified to energy. In this way, REP costs are made to comport with all other Power function costs as they go through the rate design adjustment process. The functionalization and classification of REP costs are shown in Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.3.6 (COSA 07).

### 5.2.5 Classification

Classification in the WPRDS apportions generation costs between the demand, energy, and load variance components of electric power. This classification of the generation revenue requirement is shown in Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.3.7, (COSA 08).

The classification methodology BPA uses is based on the marginal costs of the components of power and generally accepted ratemaking procedures. BPA sets the price for demand using an adjusted marginal cost of demand. For this 2002-2006 Lookback, no change was made to the original adjusted marginal cost of demand. *See* Section 2.3.1.2 of the Final WPRDS Documentation, WP-02-FS-BPA-05A for a detailed description. In addition, BPA sets the price of the Load Variance Charge using its adjusted marginal costs. For this FY 2002-2006 Lookback analysis, no change was made to the original Load Variance Charge. *See* Final WPRDS Documentation, WP-02-FS-BPA-05A, Section 2.3.4.1, for a detailed description. Sales and revenues of these products are then forecast. Forecast revenues associated with demand are classified to demand. Forecast revenues for load variance are deemed to be equal to the cost of Load Variance and therefore classified as such. Generation costs classified to energy are the residual of total generation costs not classified to demand or load variance. By virtue of this classification scheme, costs of demand or load variance are not directly allocated to customer rate pools; rather, the costs are equal to the forecast revenues. Therefore, the only allocation of costs to customer rate pools in the COSA is for costs associated with energy.

### 5.2.6 Functionalized and Classified Revenue Credits

The revenue credits described below are functionalized to generation and classified to energy. Most of these revenue credits are associated with the operation of FBS resources and have the effect of reducing the FBS resource costs to be recovered by BPA's power rates.

#### 5.2.6.1 U.S Army Corps of Engineers (COE) and Bureau of Reclamation (Reclamation) Project Revenues

COE and Reclamation Project revenues are payments from owners of downstream projects to the COE and Reclamation for benefits received (*i.e.,* additional generation) from the storage reservoirs owned by the COE and Reclamation. These revenues are not subject to revision through rates and hence are a revenue credit. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.3.8, (COSA 09).

#### 5.2.6.2 Section 4(h)(10)(C) Credits and Fish Cost Contingency Fund (FCCF)

Section 4(h)(10)(C) credits are provided by the Treasury to partially compensate BPA for the non-power portion of additional capital and operational costs that are incurred for fish migration. These credits are 27 percent of BPA's additional expenditures. This revenue was the estimate of what BPA would receive on average over a range of 50 different water conditions. The actual credit is determined after the year is completed. The operational costs vary with water conditions. The FCCF credit is similar to the section 4(h)(10)(C) credit since it is provided by the Treasury. The amount included here was the estimate based on the average of 50 water years. Only under the 15 worst water years would any credit be received, and then it would be much larger. The FCCF credit was limited by past expenditures BPA made for fish operations without receiving Treasury credits. The FCCF credit pool totaled about $325 million in the WP-02 Final Proposal. In extremely bad water years, this amount was accessed in order to avoid missing Treasury payments. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.3.8, (COSA 09).

#### 5.2.6.3 Colville Credit

The Colville credit is a credit BPA receives for being an agent of the U.S. Government and facilitating annual payments to the Colville Tribe as a result of a treaty settlement. The credit is equal to the amount BPA pays the Tribe and it is essentially a predetermined amount. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.3.8 (COSA 09).

#### 5.2.6.4 Supplemental and Entitlement Capacity

BPA receives Supplemental and Entitlement Capacity revenues from private and public utilities as a result of contracts signed many years ago where the rates are fixed at a nominal amount per year. The revenue is a predetermined amount. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.3.8 (COSA 09).

#### 5.2.6.5 Irrigation Pumping Revenues

BPA receives a small amount of income from the delivery of pumping power at rates determined according to statutory requirements subject to the direction of the Secretary of the Interior and charged to Reclamation irrigation project customers. Although this revenue is not fixed, it totals less than $500,000 per year, depending upon the weather. This revenue is paid at the end of the year to the Treasury by Reclamation for BPA's credit. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.3.8, (COSA 09).

#### 5.2.6.6 Energy Services Business Revenues

BPA received revenues associated with the activities of its Energy Services Business. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.3.8 (COSA 09).

#### 5.2.6.7 Property Transfers and Miscellaneous Revenues

Most of these estimated revenues were from contract administration, late fees, interest on late payments, and mitigation payments. These fees are not subject to change in the rate filing. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.3.8 (COSA 09).

#### 5.2.6.8 PBL Transmission Costs, Revenues, and Credits

The PBL (now Power Services), in the course of marketing power, incurs transmission-related costs and generates transmission-related revenues and credits. The costs include, but are not limited to, those associated with providing ancillary and reserve services and General Transfer Agreements (GTA). The revenues and credits are predominantly revenues associated with providing ancillary and reserve services. The net amount of these costs, revenues, and credits is classified to energy, and has the effect of reducing the FBS resource costs to be recovered by BPA's power rates. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.3.9 (COSA 10).

### 5.2.7 Allocation

Allocation is the apportionment of costs to customer classes. Allocation is performed by determining the relative sizes of resource pools and rate pools, pursuant to the rate directives contained in section 7 of the Northwest Power Act. Rate pools are groupings of customer classes (sales) for cost allocation purposes. BPA groups its sales into the "Priority Firm," "Industrial Firm," and "All Other" categories corresponding to sales under sections 7(b), 7(c), and 7(f) of the Northwest Power Act. The resource pools are those identified in the Northwest Power Act as the FBS, Residential Exchange, and NR resource pools. Costs associated with each of these respective resource pools are grouped together to facilitate allocation to rate pools. The sizes of the rate and resource pools are determined from planning load and resource balances prepared in the Load Resource Study, Section 2 above.

The Northwest Power Act establishes three rate pools. The 7(b) rate pool includes public body, cooperative, and Federal agency sales as well as the sales to utilities participating in the REP established in section 5(c) of the Northwest Power Act. The 7(c) rate pool includes sales to BPA's DSI customers. The 7(f) rate pool includes all other long-term firm power BPA sells. Subsequent to 1985, and implementation of the directives of section 7(c)(2) of the Northwest

Power Act, BPA has had, for all practical purposes, only two rate pools: the 7(b) rate pool and all other loads.

For the FY 2002-2006 Lookback, the FBS resource pool consists of: (1) the FCRPS hydroelectric projects; (2) resources acquired by the Administrator under long-term contracts in force on the effective date of the Northwest Power Act; and (3) replacements for reductions in the capability of the above resources. Costs expected to be incurred during the rate period for replacement resources were included in the FBS resource pool. *See* Load Resource Study, Section 2 above. In addition to long-term resource acquisitions, short-term power purchases are made during the rate period. These short-term power purchases augment the Federal system to achieve load/resource balance on an annual basis as well as balance the Federal system to provide operational flexibility and provide for certain fish mitigation measures on a monthly and daily basis. The costs of such balancing purchases as well as the cost of system augmentation to ensure load/resource balance are considered to be FBS costs and are allocated as such.

**5.2.7.1 Energy Cost Allocations**

The process for allocating energy costs begins with an examination of critical period firm loads and resources to determine the amount of monthly firm energy surplus or deficit. A ratemaking load and resource balance for each month of the test period is then constructed from the Load Resource Study, Section 2 above, and other data. From this ratemaking load and resource balance, service to each of the three rate pools from each of the resource pools is determined for the rate test period. Table EAF_05_01 shows the ratemaking energy loads and resources by pools. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.2.1 (EAF_05_01). Allocation factors, which apportion each resource pool's costs to BPA's classes of service, are calculated based on identified service from resource pools to rate pools in the ratemaking load and resource balances.

#### 5.2.7.2 Energy Allocation Factors

When service from each resource pool to each class of service has been identified, the amount of such service is the allocation factor for the resource pool. Resource pool costs are allocated to classes of service based on the proportions of their identified use of the resource pools to the total size (use) of the resource pool. The annual energy allocation factors for each resource pool are shown in the Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.2.2 (EAF_05_02). The Total Usage and Conservation allocation factors are the same and are based on the sum of the FBS, REP, and NR allocation factors. They are used to allocate costs and rate design adjustments to all firm energy loads. Allocated energy costs are shown in the Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.3.10 (COSA 11) and Table 5.2.4.1 (RDS 01).

#### 5.2.7.3 Other Cost Allocations

Costs not directly identifiable with rate pools, resource pools, or transmission costs allocated to the Power function are allocated as described below.

##### 5.2.7.3.1 Conservation Costs

The Northwest Power Act requires BPA to treat cost-effective conservation as an electric power resource in planning to meet the Administrator's obligations to serve loads. The "legacy conservation" line item, as seen in the COSA 06 tables (*see* Lookback Documentation, WP-07-E-BPA-44A, Section 5.2.3), includes: (1) debt service for BPA's previous resource acquisition activities; (2) BPA's continuing contributions to the region's market transformation efforts; and (3) a share of the agency's total planned net revenues. The "conservation augmentation" line item, as seen in the COSA 06 tables (*see* Lookback Documentation, WP-07-E-BPA-44A, Section 5.2.3) includes costs associated with forecasted conservation for the FY 2002-2006 time period. In addition, the Northwest Power Act indicates that BPA should encourage the development of conservation and renewable resources in the region. Toward that end, the "energy efficiency" expenses line item, as seen in the COSA 06 tables (*see* Lookback Documentation, WP-07-E-BPA-44A, Section 5.2.3), reflects BPA's costs associated with providing conservation and renewable resources information in the region. In addition, these costs represent the technical support BPA provides in the region in the area of energy efficiency. The "energy efficiency" revenue line item seen in Table COSA 09 (*see* Lookback Documentation, WP-07-E-BPA-44A, Section 5.2.3), reflects payments provided by other BPA organizations and Federal agencies for the energy efficiency services delivered.

**5.2.7.3.2 BPA Program Costs**

Some of BPA's program costs are not directly identified with any specific resource pool, or customer class. An example is the cost of the ratemaking process. The generation portion of these costs is determined in the Revenue Requirement Study, WP-02-FS-BPA-02. The generation portion appears as BPA program costs. These costs, as seen in Table COSA 11 (*see* Lookback Documentation, WP-07-E-BPA-44A, Section 5.2.3), are allocated uniformly to all customer classes based on the total usage allocation factors for energy.

**5.2.7.3.3 WNP-3 Settlement Exchange Agreement Costs**

The revenue requirement includes costs related to the WNP-3 Settlement Exchange Agreement between BPA and four IOUs that have a 30 percent interest in the WNP-3 nuclear plant. Two types of WNP-3 Settlement Exchange costs are allocated in the COSA: plant-related costs and exchange energy costs. Under the WNP-3 Settlement Agreement, BPA is obligated to serve a specified amount of IOU load. Whether BPA must purchase to serve WNP-3 obligations is determined in RiskMod. To serve the IOU load, BPA may purchase either Company Exchange Energy from the IOUs or other, lower-cost power. The exchange energy costs are the projected costs of purchases of Company Exchange Energy (which may not exceed the costs of combustion turbines) or other purchases and storage in lieu of Company Exchange Energy. These costs are allocated uniformly to all loads using the total usage allocation factors for energy. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.4.1 (RDS 01).

**5.2.7.3.4 Planned Net Revenues for Risk (PNRR)**

PNRR is the amount of net revenues required to ensure that cash-flow from proposed rates fully meets BPA's probability standard for repaying Treasury on time and in full. The PNRR are functionalized entirely to generation and are allocated to resource pools that include Federal capital investments. The methodology is described and illustrated in the Revenue Requirement Study, WP-02-FS-BPA-02. For this FY 2002-2006 Lookback, the PNRR amount was not changed from the WP-02 Final Proposal.

The PNRR value found in the COSA 06 tables was the result of an iterative process between the RAM, the RiskMod, Non-Operating Risk Model (NORM) and the ToolKit models. The iteration was initiated with a seed value for PNRR in COSA 06 of the RAM. The resultant rates were used in RiskMod to produce probability distributions. These distributions were then used in the ToolKit to produce a new PNRR value and ending cash reserve amounts for new COSA 06 tables. *See* Lookback Documentation, WP-07-E-BPA-44A, Section 5. For a further explanation of this iterative process, *see* Doubleday, *et al.*, WP-02-E-BPA-18. The PNRR value used in this FY 2002-2006 Lookback is the same as that used in the WP-02 Final Proposal.

**5.2.8 COSA Results**

The result of the COSA process is the allocation of the test period revenue requirements for energy to classes of service served with firm power. Tables COSA 11 and RDS 01 summarize the allocated generation energy revenue requirements and the total allocated revenue requirement recoverable from power rate classes of service, including transmission costs allocated to the

Power function, that are recoverable from these classes of service. *See* Lookback Documentation, WP-07-E-BPA-44A, Tables 5.2.3 (COSA 11) and Table 5.2.4 (RDS 01).

### 5.2.9 Rate Design Step Adjustments

Rate design adjustments are performed sequentially in the order described below.

#### 5.2.9.1 Excess Revenue Adjustment

The Excess Revenue Adjustment recognizes that revenues will be collected from certain classes of service to which costs are not allocated and credits these revenues to other customer classes. The source of excess revenues is projected secondary energy sales.

##### 5.2.9.1.1 Secondary Energy Sales

On a planning basis and with system augmentation, BPA will have firm resources available to meet firm load obligations under 1937 water conditions. However, rates are set assuming that better than critical water conditions occur and, therefore, secondary energy sales and revenues are projected. These sales and revenues are projected on the 50-water year run of the RiskMod model. *See* Conger, *et al.,* WP-02-E-BPA-15. The projected secondary energy revenue credits are allocated to firm loads so that BPA does not recover more than its revenue requirements. In previous rate cases, secondary energy revenue was referred to as "nonfirm" energy revenue. The secondary energy revenue value used in this FY 2002-2006 Lookback is the same as that used in the WP-02 Final Proposal.

The RiskMod model is used to project the level of secondary energy sales and revenues. BPA expected to sell secondary energy that will produce $2.578 billion in revenues over the five-year test period. After reducing these revenues by transmission charges totaling $348.7 million, BPA credited its firm power customers with excess revenues totaling $2.229 billion over the five-year test period. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.4.4, (RDS 11).

**5.2.9.1.2 Allocation of Excess Revenues**

Secondary energy revenues are used first to pay transmission costs associated with sales of secondary energy, with the remainder credited to firm power customers. These excess revenues are functionalized to generation and classified to energy. They are then allocated to loads served with Federal system resources (FBS and NR). The generation-related excess revenues are allocated in this manner because they are associated with secondary energy service and the cost of secondary energy is based on Federal resource costs only. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.4.5 (RDS 12).

The Nonfirm Energy (NF) Standard rate was based on the average cost of nonfirm energy. Table RDS 05 shows the calculation of the average cost of nonfirm energy. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.4.2 (RDS 05).

**5.2.9.2 Firm Power Revenue Deficiencies Adjustment**

BPA sold firm power at contractual rates and in the open market under the FPS-96 rate schedule. Sales of such firm power were not necessarily made at the fully allocated costs of the power. Therefore, either a revenue surplus or a revenue deficiency would result when a comparison is made between the costs allocated to the firm power and the revenues received from the sale of such power. BPA determined that in the FY 2002-2006 period it would receive $2.308 billion in revenues from the sale of firm power in various PNW and Southwest markets. Based on these sales estimates, transmission costs were estimated to be $260.4 million. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.4.4 (RDS 11). BPA allocated $3.300 billion in generation costs to the firm power sold. Therefore, there was a revenue deficiency of

$1.253 billion over the five-year test period. This revenue deficiency of allocated costs in excess of revenues was charged to all firm power (PF, IP, NR) customers. *See* Lookback Documentation, WP-07-E-BPA-44A, Tables 5.2.4.6 and 5.2.4.7, (RDS 17 and RDS 18).

**5.2.9.3 7(c)(2) Adjustment**

DSI rates are based on sections 7(c)(1), 7(c)(2), and 7(c)(3) of the Northwest Power Act. Section 7(c)(1)(B) provides that after July 1, 1985, the DSI rates will be set "at a level, which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." Pursuant to section 7(c)(2), the DSI rates are to be based on BPA's "applicable wholesale rates" to its preference customers and the "typical margins" included by those customers in their retail industrial rates. Section 7(c)(3) provides that the DSI rates are also to be adjusted to account for the value of power system reserves provided through contractual rights that allow BPA to restrict portions of the DSI load. This adjustment is typically made through a Value of Reserves (VOR) credit. To more accurately reflect the product BPA may purchase from the DSI customers, the name has been changed to Supplemental Contingency Reserve Adjustment (SCRA). However, for the WP-02 Final Proposal, BPA did not propose a uniform SCRA credit to be applied against DSI rates. Thus, the DSI rates were set equal to the applicable wholesale rate, plus a typical margin, subject to the DSI floor rate test and the outcome of the section 7(b)(2) rate test. *See* Section 2.3.4 below.

The applicable wholesale rate is the PF rate (in combination with the NR rate if new NLSLs were projected for the test period) at the DSI load factor. The typical margin is based on the overhead costs that preference customers add to BPA's price of power in setting their retail industrial rates. The typical margin value used in this FY 2002-2006 Lookback is the same as that used in the WP-02 Final Proposal.

The methods and calculations used to determine the typical margin are discussed in detail in Appendix A of the 2002 Final WPRDS. *See* WPRDS, Appendix A, WP-02-FS-BPA-05.

The net margin was 0.42 mills per kWh. As stated above, a zero SCRA credit was forecast in the WP-02 Final Proposal. This net margin was added to the seasonal and diurnal PF energy charges. These adjusted PF energy charges and the charge for demand were applied to the DSI test period billing determinants to determine the initial IP rate. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.4.9 (RDS 20).

The 7(c)(2) adjustment is necessary to account for the difference between the revenues BPA expects to recover from the DSIs at the initial IP rate and the costs allocated to the DSIs. This difference, known as the 7(c)(2) delta, is allocated to non-DSI customers, primarily the PF customers. Because the allocation of the 7(c)(2) delta changes the PF rate upon which the IP rate is based, the entire process is repeated with the revised PF rate from the previous iteration until the size of the 7(c)(2) delta does not change when a successive iteration is performed. This process is accomplished through an algebraic solution that is shown in Table 5.2.4.10, RDS 21. *See* Lookback Documentation, WP-07-E-BPA-44A, Section 5.2.4.

The size of the 7(c)(2) delta for the five-year test period was $953.9 million. This amount was allocated to PF and NR loads. The allocation was based on the energy allocation factors developed in the COSA. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.4.11 (RDS 22).

**5.2.9.4 7(b)(2) Adjustment**

The rate test specified in section 7(b)(2) of the Northwest Power Act ensures that BPA's public body, cooperative, and Federal agency customers' firm power rates applied to their requirements loads are no higher than rates calculated using specific assumptions that remove certain effects of the Northwest Power Act. If the 7(b)(2) rate test triggers, the public body, cooperative, and Federal agency customers are entitled to rate protection. The cost of this rate protection is borne by other purchasers of firm power. In order to make these cost adjustments, the PF rate is bifurcated. The two resulting rates are the PF Preference rate and PF Exchange Program rate.

The Section 7(b)(2) Rate Test Study, Section 6 below, indicates the 7(b)(2) rate test has triggered and the PF rate applicable to BPA's preference customers must be adjusted down. The amount of protection needed is implemented through a reduction of the PF Preference rate in mills/kWh. BPA makes three adjustments in the rate design sequence to provide this protection to its preference customers and allocate the costs of the rate protection.

First, the PF Preference customer class is given a credit, which reduces its rate, by the amount of the protection indicated in the Section 7(b)(2) Rate Test Study, Section 6 below.
The 2.5 mills/kWh protection amount results in a credit of $648.3 million to these customers. The cost of providing this protection is allocated to the remaining firm power customers in the rate design process (PF Exchange, IP, and NR). *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.4.15 (RDS 31).

The second adjustment is the 7(b)(2) Industrial Adjustment. The amount of this adjustment is the value of a recalculated 7(c)(2) delta at the lower PF Preference rate. The amount of the new 7(c)(2) delta is $157.8 million. This amount is allocated to the PF Exchange customer class and to the NR customer class. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.4.17 (RDS 34).

A third adjustment is necessary to allocate an increase in the gross Residential Exchange costs resulting from the bifurcation of the PF rate causing the PF Exchange Program rate to be higher than the average combined rate before the bifurcation. This results in higher Residential Exchange ASCs for deeming utilities. Therefore, the gross costs of the Residential Exchange must be recalculated. Any increase in such costs can only be allocated to the PF Exchange rate and the NR rate. The amount of the adjustment is $0 million and is determined through a set of iterations of the Residential Exchange cost model. The allocation of this amount is performed in the Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.4.19 (RDS 34A).

After the three 7(b)(2) adjustments are made (in the absence of a need for a DSI floor rate adjustment), BPA is then able to calculate Rate Design Step energy rates for the firm power classes of service. If the DSI rate falls below the floor rate, however, one final adjustment is necessary.

**5.2.9.5 DSI Floor Rate Test**

Section 7(c)(2) of the Northwest Power Act requires that the DSI rates in the post-1985 period "shall in no event be less than the rates in effect for the contract year ending June 30, 1985." Accordingly, a floor rate test is performed to determine if the IP rate has been set at a level below the floor rate. If so, an adjustment is made that raises the DSI rate to recover revenues at the floor rate and credits other customers with the increased revenue from the DSIs. If the DSI rate has been set at a level above the floor rate, no floor rate adjustment is necessary.

The first step in calculating the floor rate is to apply the IP-83 Standard rate charges to test period (FY 2002-2006) DSI billing determinants. Although the energy billing determinants used for this calculation are identical to the energy billing determinants for the proposed rates, the demand billing determinants are different. The IP-83 Demand Charges are applied to billing determinants based on non-coincidental demand. The resulting revenue figure is then divided by total IP test period loads to arrive at an average rate in mills/kWh. This rate is reduced by an Exchange Cost Adjustment and a deferral that were included in the IP-83 rate. Both adjustments are made on a mills/kWh basis.

BPA has removed all transmission costs from the IP-83 rate to make a power-only floor rate comparison. The floor rate was adjusted for transmission costs by subtracting total transmission costs in mills/kWh from the original floor rate in the same manner that the Exchange Cost adjustment and deferral adjustments were completed. The mills/kWh amount was determined by dividing total transmission costs in the IP-83 rate by the total energy billing determinants for that rate period. The transmission cost adjustment amounted to 3.81 mills/kWh.

These calculations result in an undelivered DSI floor rate of 20.98 mills/kWh. The floor rate is then applied to the test period DSI billing determinants to determine floor rate revenues. Revenues at the proposed IP rate charges are compared to revenues at the floor rate. Because the proposed IP rate revenues are greater than the floor rate revenues, no adjustment is necessary to the Rate Design Step IP rate. Tables 5.2.4.12 and 5.2.4.13, RDS 23 and RDS 24 show the DSI floor rate calculation. *See* Lookback Documentation, WP-07-E-BPA-44A, Section 5.2.4.

#### 5.2.9.6 Rate Design Contra

The Rate Design Step adjustments move allocated costs between classes of service or adjust rates to account for excess revenues. Each rate design adjustment shows the classes of service to which the amount of the adjustment went. What is not shown for each rate design adjustment is the complementary accounting entry showing the source of the adjustment. The RAM keeps track of all such complementary accounting. When COSA allocated costs and rate design adjustments are summarized, it is necessary to further adjust the allocated costs by the amount of the complementary transactions. Such amounts are referred to as the rate design contra, which must be applied so that final allocated and adjusted costs to all rate classes will equal BPA's revenue requirements. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 5.2.4.22 (RDS 40).

#### 5.2.9.7 Rate Design Results

Table RDS 41 summarizes the allocated costs and rate design adjustments for each class of service. Rate charges are calculated for each class by dividing the allocated and adjusted energy costs by the appropriate billing determinants. Summaries of the adjusted annual average energy rate charges are shown on Tables RDS 50, 51, and 52. *See* Lookback Documentation, WP-07-E-BPA-44A, Tables RDS 41 (RDS 50, RDS 51, and RDS 52). These annual average energy rates are shaped into monthly and diurnal periods based on the results of the WP-02 Marginal Cost Analysis Study, WP-02-FS-BPA-04.

### 5.2.10 Slice Cost Calculation

Because the purpose of the Lookback is to recalculate the PF Exchange rate and other rates necessary for the proper application of CRACs, and because the Slice rate was not subject to CRACs, the recalculation of the Slice rate was not necessary for the Lookback.

## 5.3 FY 2002-2006 Lookback Post-Processor Modeling

The FY 2002-2006 Lookback Post-Processor is a simplified model that determines the level of the PF Exchange rate for each year of the rate period and calculates what the IOUs' REP benefits would have been in the absence of the REP settlements.

The model uses the recalculated base PF Preference and PF Exchange rates from the FY 2002-2006 Lookback RAM2002 analysis. See Lookback Documentation, WP-07-E-BPA-44, Section 5.2. The model calculates a set of annual CRACs that adjust the PF Preference and PF Exchange rates so that they will recover the proper revenues for the rate period.

To determine the revenues to be recovered from the CRAC'd rates, the actual revenues recovered from actual rates in effect during the rate period is determined. The actual revenues collected for the rate period are then adjusted by: (1) subtracting the amount of REP Settlement Agreement Benefits paid as expressed in Section 13; (2) subtracting the net cost to BPA of furnishing power to IOUs, included in Section 13; and (3) adding the net REP benefits determined by using the recalculated base PF Exchange rate and the backcast utility ASCs and eligible exchangeable loads, as expressed in Section 14. These annual adjusted revenue amounts for each fiscal year are the "Annual Revenue Targets."

For the Lookback analysis, it is assumed that all other revenues and credits except those provided by firm sales under PF rates remain the same in a world with or without the REP settlements. Therefore, only PF rate revenues are used in the model to determine the Annual Revenue Targets.

If the model projects that revenues from recalculated rates fall short of the Annual Revenue Targets for a year, then the base PF Preference and PF Exchange rates are increased by means of a CRAC percentage increase to both rates. The CRAC increases the revenue and, in turn, decreases the level of net REP benefits until the difference between the net revenues collected and the Annual Revenue Target is zero. The inverse is true if revenues over-collect the Annual Revenue Target. The calculated IOU REP FY 2002-2006 benefits at the CRAC'd PF Exchange rates are then reported out to be used in the Lookback Amount calculations. *See* Lookback Documentation, WP-07-E-BPA-44A, Tables 5.3.1, 5.3.2, 5.3.3, 5.3.4, 5.3.5, and 5.3.6.

## 5.4 Rate Analysis Results

The FY 2002-2006 Lookback base rates from the WP-02 RAM2002 are: a PF Preference rate of 27.52 mills/kWh and a PF Exchange rate of 38.12 mills/kWh. The average CRAC'd PF Preference is 28.81 mills/kWh and the average CRAC'd PF Exchange rate is 39.90 mills/kWh. The Lookback recalculated IOU REP benefits for FY 2002-2006 average about $205 million per year. *See* Table 14.1 in this Study and Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.7, Table 9.2.8, and Table 9.2.9.

# 6. SECTION 7(b)(2) RATE TEST STUDY, FY 2002-2006

## 6.1 Introduction

This section addresses the section 7(b)(2) rate test for FY 2002-2006 Lookback analysis. Recalculations of the section 7(b)(2) rate tests are necessary to determine a base PF Exchange rates to be used in the Lookback analysis. There are two phases of the 7(b)(2) rate test for the Lookback analysis, the FY 2002-2006 rate test and FY 2007-2009 rate test. The first rate test was conducted using data available from both the WP-02 Final Proposal and the WP-02 Supplemental Proposal in and around the spring of 2001. In addition, assumption changes have been made to reflect the changed conditions due to removal of the REP settlements. The second rate test was conducted using the data available from the WP-07 Final Proposal, and is discussed in Section 10.

Section 7(b)(2) of the Northwest Power Act, 16 U.S.C. § 839e(b)(2), directs the BPA to conduct 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 four 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 PF preference customers' wholesale firm power rates from certain specified costs resulting from provisions of the Northwest Power Act. The rate test can result in a reallocation of costs from the general requirements loads of PF preference customers to other BPA loads.

The rate test involves the projection and comparison of two sets of wholesale power rates for the general requirements loads of BPA's public body, cooperative, and Federal agency customers (7(b)(2) Customers). The two sets of rates are: (1) a set for the rate period and the ensuing four years assuming that Section 7(b)(2) is not in effect (Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (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. It should be noted that a different treatment of applicable 7(g) costs is proposed in its Supplemental Proposal for FY 2009. However, this Lookback rate test is using the existing 1984 Implementation Methodology treatment of applicable 7(g) costs. Next, each of the nominal rates for the two cases is discounted to the beginning of the rate period. 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 Program Case rate is greater than the average 7(b)(2) Case rate, the rate test triggers. The difference between the average Program Case rate and the average 7(b)(2) Case rate determines the amount to be reallocated from the 7(b)(2) Customers to other firm loads.

#### 6.1.1 Purpose and Organization of Study

The purpose of this study is to describe the application and results of the Section 7(b)(2) Rate Test Methodology for the FY 2002-2006 Lookback analysis. If the 7(b)(2) rate test triggers, and it does, the cost adjustment amount that is to be incorporated into the rate design process is calculated. The Lookback Documentation, WP-07-E-BPA-44A, Section 6, contains the documentation of the Excel models and data used to perform the 7(b)(2) rate test.

This section is organized into two major sub-sections. The first 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 and the results of the rate test for the FY 2002-2006 Lookback analysis. The second section presents a set of tables that presents the calculations performed for the rate test and the results of the test. The financing benefits analysis has not been changed from that used in the WP-02 Final Proposal and is not included in this study. *See* Section 7(b)(2) Rate Test Study Documentation, WP-02-FS-BPA-06A, Appendix A.

### 6.1.2 Basis of Study

#### 6.1.2.1 Legal Interpretation

Prior to the first phase of its 1985 general rate proceeding, BPA published the Legal Interpretation of section 7(b)(2) of the Northwest Power Act (1984 Legal Interpretation), 49 FR 23,998 (1984). The 1984 Legal Interpretation is hereby incorporated by reference. Major provisions of the 1984 Legal Interpretation are listed below. It should be noted that BPA is revising the 1984 Legal Interpretation as part of this Supplemental Proceeding. However, except for the treatment of Mid-Columbia resources, this FY 2002-2006 Lookback analysis is being conducted under the 1984 Legal Interpretation.

##### 6.1.2.1.1 Legal Interpretation: Five Assumptions

The 7(b)(2) Case is modeled by limiting the differences between the two cases to only the five assumptions specified in section 7(b)(2) and the unavoidable natural consequences of those assumptions on the ratemaking processes; all others assumptions remain the same between the Program Case and the 7(b)(2) Case.

##### 6.1.2.1.2 Legal Interpretation: 7(a) Limitation

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 Act.

##### 6.1.2.1.3 Legal Interpretation: Applicable 7(g) Costs

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. Please note that the proposed Legal Interpretation modifies the language to specify that applicable 7(g) costs are to be subtracted from both the

Program and 7(b)(2) Cases. The treatment of applicable 7(g) costs in this rate test is the same as it was for the WP-02 Final Proposal.

#### 6.1.2.1.4 Legal Interpretation: DSI Service

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

#### 6.1.2.1.5 Legal Interpretation: DSI Served as Firm

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

#### 6.1.2.1.6 Legal Interpretation: Within or Adjacent

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.

#### 6.1.2.1.7 Legal Interpretation: Federal Base System

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 power sales contracts with the DSIs expire.

#### 6.1.2.1.8 Legal Interpretation: 7(b)(2)(D) Resource Stack

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 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.  Please note that the proposed Legal Interpretation would exclude the Mid-Columbia resources from the 7(b)(2) Case resource stack.

#### 6.1.2.2 Implementation Methodology

A hearing pursuant to section 7(i) of the Northwest Power Act was held during 1984 on rate test implementation methodology issues.  The issues addressed in the hearing are discussed in the Administrator's Record of Decision (ROD) for Section 7(b)(2) Implementation Methodology (7(b)(2) ROD), b-2-84-F-02, published in August 1984.  The 1984 Implementation Methodology and ROD are hereby incorporated by reference.  In this Supplemental Proposal, BPA is proposing a revised Section 7(b)(2) Implementation Methodology.  However, except for the treatment of Mid-Columbia resources, this FY 2002-2006 Lookback analysis is being conducted under the 1984 Implementation Methodology.  The major issues resolved in the 1984 Implementation Methodology are discussed below.

##### 6.1.2.2.1 Implementation Methodology:  Reserve Benefits

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* Documentation for Wholesale Power Rate Development Study, WP-02-E-BPA-05, Appendix B.  In the WP-02 Final Proposal, reserves provided under the Northwest Power Act were forecast to be zero.  This assumption eliminated the need for a financing benefits analysis to quantify the value of reserves for the rate test.

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 analysis used in this FY 2002-2006 Lookback rate test is unchanged from that used in the WP-02 Final Proposal. The financing benefits in the 7(b)(2) Case were estimated by a financial consultant, Sutro & Co. Incorporated, who estimated the resource sponsor's financial cost for the 7(b)(2)(D) resources assuming that BPA did not acquire the resource output. The changed financing benefits from the Program Case assumptions for those resources required to meet the 7(b)(2) Customers' loads may increase the costs of those resources in the 7(b)(2) Case. *See* Section 7(b)(2) Rate Test Study Documentation, WP-02-FS-BPA-06A.

**6.1.2.2.2 Implementation Methodology: Natural Consequences**

Natural consequences result from reflecting the five 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 nonfirm energy markets. It should be noted that BPA is proposing a different treatment of elasticity of demand in the proposed Implementation Methodology.

**6.1.2.2.3 Implementation Methodology: Rate Modeling**

The 7(b)(2) rate test in the FY 2002-2006 Lookback was conducted using three large spreadsheet models. The first of the spreadsheet models is the Program Case RAM (RAM-Prog), used to calculate Program Case rates. RAM-Prog is the same model used to calculate the WP-02 Final Proposal rates. The second model is a 7(b)(2) Case version of the RAM (RAM-7b2). RAM-7b2 model differs from RAM-Prog by only the five assumptions specified in section 7(b)(2) and the natural consequences of those assumptions on the results of ratemaking processes. The third model is the Residential Exchange Model of the RAM (ResExRAM), which calculates the costs of the REP and electronically transfers that information to RAM-Prog. The output of these spreadsheet models is in the Lookback Documentation, WP-07-E-BPA-44A, Section 6.

#### 6.1.2.2.4 Implementation Methodology: Rate Discounting

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 simple average of the discounted rates for the Program Case exceeds the simple 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 billing determinants of the PF Preference customers for the rate period to determine the amount of costs to be reallocated from the PF Preference customers to other BPA firm loads in the rate period.

## 6.2 Methodology

Implementing section 7(b)(2) consists of incorporating the determinations from the 1984 Legal Interpretation and the 1984 Implementation Methodology ROD into the RAM-Prog and RAM-7B2 models.

### 6.2.1 Sequence of Steps

The RAM-Prog and RAM-7B2 models simulate BPA's ratemaking process by performing the steps needed to develop wholesale power rates. Each step is described as it is performed to calculate rates for the Program Case and the 7(b)(2) Case.

#### 6.2.1.1 Program Case RAM

This model calculates annual Program Case rates for FY 2002-2006 and the following four years, FY 2007-2010. Except for the treatment of Mid-Columbia and conservation resources, the ratemaking methodology used to calculate rates for the Program Case of the 7(b)(2) test are identical to those used in calculating average rates for the WP-02 Final Proposal. However, as discussed below, the data used in this FY 2002-2006 Lookback analysis is in some cases substantially different that the data used in the WP-02 Final Proposal.

#### 6.2.1.1.1 Sales

For this FY 2002-2006 Lookback analysis, the sales forecast used to develop rates for the Program Case covers the period FY 2002-2010, and is the same forecast used to develop BPA's FY 2002-2006 Lookback base rates described in Section 5.2. Sales forecasts are as explained Section 2. Exchange loads are explained in Section 7. For this FY 2002-2006 Lookback analysis, the assumption is for 1,440 aMW of sales to the DSIs. *See* Final WPRDS Documentation, WP-02-FS-BPA-05A, pages 93 and 94.

BPA's total sales obligations are comprised of COUs, IOUs, DSIs, Federal agencies, Residential Exchange load, and contractual sales. All forecasted sales are entered into the RAM models with diurnally and seasonally differentiated energy and seasonally differentiated demand billing determinants.

#### 6.2.1.1.2 Load/Resource Balance

The RAM models do not perform load/resource balance calculations. Rather, the models depend on the load/resource balance performed in the Loads and Resources Study, Section 2. Data from the Loads and Resources Study are used to ensure that resources are allocated to serve loads in the order prescribed by the Northwest Power Act. The FBS serves PF loads (Federal agency, COU, 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 resources and new resources are used to serve this combined rate pool.

#### 6.2.1.1.3 Revenue Requirement

The revenue requirement for this FY 2002-2006 Lookback analysis is explained in Section 3. The majority of the change is associated with greater COU loads, greater system augmentation costs and greater gross costs of the REP. FBS costs are based on the interest and amortization of the Federal debt for the hydro projects; planned net revenues; hydro operation and maintenance costs; costs related to WNP-1, -2, and -3, not including the costs associated with the WNP-3 Settlement Agreement; fish and wildlife costs; costs of the Hanford and Trojan nuclear plants; costs of hydro efficiency improvements; costs of system augmentation; and costs of balancing purchase power. Residential Exchange resource costs are based on the ASCs of utilities participating in the REP. New resource costs are those of the Idaho Falls contract, the generation portion of competitive acquisitions, geothermal, the Cowlitz Falls Project, and other firm purchased power. Other BPA costs include BPA's administrative and general costs, the costs associated with the WNP-3 Settlement Agreement, and the costs associated with BPA legacy conservation and energy efficiency programs.

#### 6.2.1.1.4 Cost Allocation

Allocation of projected costs to customer classes is performed on an average energy basis in the RAM-PROG and RAM-7B2 models. Generation costs are allocated by the use of Energy Allocation Factors calculated using the results of the Loads and Resources Study. Conservation and billing credit costs, BPA administrative and general expenses, energy service business revenues, and WNP-3 Settlement Agreement costs are allocated across all BPA firm loads. The cost allocation procedures for the Program Case are the same as those for the WP-02 Final Proposal.

#### 6.2.1.1.5 Rate Design

The adjustments made to allocated costs in the RAM-PROG for the Program Case are the same as those made in the WP-02 Final Proposal. These adjustments include excess revenue credits; the surplus firm power revenue surplus/deficiency; the section 7(c)(2) delta and margin; the DSI floor rate adjustment; and the exchange cost adjustment.

Excess Revenues are earned from the sale of secondary energy that is assumed available from the average of 50-water years for secondary energy generation. Excess revenues are credited to loads served by FBS and new resources. The RAM-PROG and RAM-7B2 models use the secondary energy sales revenue forecast produced by the RiskMod model, documented in the Final Risk Analysis Study, WP-02-FS-BPA-03. For this FY 2002-2006 Lookback analysis, no changes are made to the original levels of secondary energy sales from the WP-02 Final Proposal.

The Surplus Firm Power Revenue Surplus/Deficiency results when the available surplus firm power is sold at other than its fully allocated cost. In addition, BPA assumes that long-term extra-regional contracts will continue in the power sales mode, at amounts and rates set by the individual contracts. For this FY 2002-2006 Lookback analysis, no changes are made to the WP-02 Final Proposal levels of surplus firm power sales. The fully allocated cost of the surplus firm power, less the revenues received from the sale of that power after transmission costs are deducted, 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 like 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 0.46 mills/kWh in nominal dollars. The DSI rate equals the applicable wholesale rate to PF Preference customers plus the net margin.

The DSI Floor Rate test ensures that the DSI rate will not be lower than the Industrial Firm Power rate in effect for Operating Year 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.

The Residential Exchange Cost Adjustment alters BPA's revenue requirement because changes in the PF rate result in changes in the cost of the REP. RAM-Prog iterates with the ResExRAM to converge on the cost of the REP that is associated with the calculated PF rate. *See* Lookback Documentation, WP-07-E-BPA-44A, Section 6, Table COSA 06.

Rate Mitigation, Low Density Discount costs, and Conservation and Renewables (C&RD) Discount costs are included in the rate calculations for the PF rate class. For this Lookback analysis, no changes are made to the WP-02 Final Proposal levels of Low Density Discount costs and C&RD costs. For a further discussion of these items, *see* Sections 2.8, 2.9, and 2.10 in the Final WPRDS, WP-02-FS-BPA-05.

**6.2.1.2 7(b)(2) Case**

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

#### 6.2.1.2.1 Sales

The sales forecasts input to RAM-7B2 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) Customer 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 to be served by IOUs.

#### 6.2.1.2.2 Resources

The size of the FBS is identical for the two cases, Program Case and the 7(b)(2) Case. If the FBS is insufficient to serve all 7(b)(2) Customer loads in the 7(b)(2) Case, additional resources are assumed to come on-line. Consistent with the 1984 Implementation Methodology, three types of additional resources can be added to serve loads. As discussed in Doubleday, *et al.*, WP-07-E-BPA-60, the portions of the Mid-Columbia Hydro resources that are contracted to regional IOUs were not considered to be non-dedicated for purposes of the 7(b)(2) rate test. Therefore, these resources were removed from the 7(b)(2)(D) resource stack. In addition, BPA has removed obsolete programmatic conservation resources from the 7(b)(2)(D) resource stack. Sufficient 7(b)(2)(D) stack resources were available to meet 7(b)(2) Case loads through the rate test period. The cost of resources brought on-line in the 7(b)(2) Case is affected by the 7(b)(2) financing benefits analysis.

#### 6.2.1.2.3 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, Sutro & Co. Incorporated. As stated above, the financing analysis has not been changed from that used in the WP-02 Final Proposal.

*See* WP-02-FS-BPA-06A. The financial advisor's analysis appears as Appendix A to that document. 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 14 basis points lower than the 7(b)(2) Case without BPA backing. This increases the financing costs for additional resources in the 7(b)(2) Case, thereby increasing the 7(b)(2) Case power cost for the 7(b)(2) Customers. For the Cowlitz Falls Project, the estimated benefit of BPA's participation is 24 basis points between an assumed revenue bond issued with and without a BPA contract for the project. BPA sponsored programmatic conservation is 4 basis points lower than the same activities under the 7(b)(2) Case without BPA backing. The debt associated with the Idaho Falls Project was refunded to take advantage of lower interest rates. However, since the owner of the project, the City of Idaho Falls, can withdraw from the contract with BPA at its option, the new interest rate is not affected by Idaho Falls' contractual relationship with BPA. Therefore, no financing differential is associated with Idaho Falls.

**6.2.1.2.4 Load/Resource Balance**

For this FY 2002-2006 Lookback analysis, 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. The Program Case is in load/resource balance during the rate period. The 7(b)(2) Case sales assume no conservation savings and are therefore greater than the Program Case sales. The FBS was insufficient to meet the 7(b)(2) Customer loads in some of the years during the FY 2002-2010 rate test period, therefore additional resources were needed. These additional resources were taken from the 7(b)(2)(D) resource stack in the order of least cost first and their cost is added to the 7(b)(2) Case revenue requirement. The addition of these resources provides more power capability than is necessary to achieve load/resource balance, thus increasing the availability of surplus firm power in the 7(b)(2) Case. Therefore, additional surplus power sales revenues were forecast in the 7(b)(2) Case. *See* Lookback Documentation, WP-07-E-BPA-44A, Section 6, Table 7b2Resource_01.

#### 6.2.1.2.5 Revenue Requirement

The revenue requirement in the 7(b)(2) Case is comprised of the same 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 of new resources and REP costs. Repayment studies are then performed for each year of the 7(b)(2) rate test period using the same methodology as for the Program Case.

#### 6.2.1.2.6 Cost Allocation

Section 7(b)(2) Customers are allocated costs of the 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.

#### 6.2.1.2.7 Rate Design

In the WP-02 Final Proposal, BPA estimated reserve benefits provided by the DSIs to be zero. *See* Section 1.2.2.1 above and the Final WPRDS, WP-02-FS-BPA-05, Appendix B. However, an estimate of possible stability reserves provided by the DSIs to the Transmission was included. *See* Lookback Documentation, WP-07-E-BPA-44A, Section 6, Table RDS 11. Other rate design adjustments in the 7(b)(2) Case are performed in the same manner as in the Program Case.

### 6.3 Summary of Results

Results for the two cases are summarized in Tables 6.1 and 6.2 below.

### 6.3.1 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 WP-02 Final Proposal. Table 6.1 below shows the projection of undiscounted nominal Program Case rates.

### 6.3.2 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 resources from the 7(b)(2)(D) stack. 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 6.2 below shows the projection of undiscounted nominal 7(b)(2) Case rates.

### 6.3.3 The Rate Test

The RAM-PROG model performs the section 7(b)(2) rate test after it and the RAM-7b2 model calculate the two sets of 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 the WP-02 Final Proposal rate test are comprised of BPA-acquired and projected conservation and billing credits, energy efficiency costs, and C&RD costs. The projected rates for each year then are discounted to FY 2002 using factors based on BPA's projected borrowing rate for each year. Table 6.3 below 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 6.4 below). As shown in Table 6.4 below, the rate test triggers. Therefore, a rate adjustment is required. *See* Section 5.

**TABLE 6.1**
**PROGRAM CASE RATES**
(nominal mills/kWh)

| Fiscal Year | Rate | Applicable 7(g) Costs | Net Rate |
|---|---|---|---|
| 2002 | 32.947 | 1.904 | 31.044 |
| 2003 | 32.256 | 1.951 | 30.305 |
| 2004 | 32.893 | 1.974 | 30.919 |
| 2005 | 33.110 | 2.145 | 30.965 |
| 2006 | 33.279 | 2.363 | 30.916 |
| 2007 | 34.305 | 2.271 | 32.034 |
| 2008 | 34.174 | 2.390 | 31.784 |
| 2009 | 34.957 | 2.600 | 32.356 |
| 2010 | 34.665 | 2.887 | 31.779 |

**TABLE 6.2**
**7(b)(2) CASE RATES**
(nominal mills/kWh)

| Fiscal Year | 7(b)(2) Rate |
|---|---|
| 2002 | 25.611 |
| 2003 | 24.862 |
| 2004 | 25.531 |
| 2005 | 25.681 |
| 2006 | 25.829 |
| 2007 | 29.711 |
| 2008 | 30.440 |
| 2009 | 32.770 |
| 2010 | 34.435 |

**TABLE 6.3**
**DISCOUNT FACTORS FOR THE RATE TEST**

| Fiscal Year | Annual BPA Borrowing Rate | Cumulative Discount Factor |
|---|---|---|
| 2002 | .0708 | .9339 |
| 2003 | .0689 | .8737 |
| 2004 | .0690 | .8173 |
| 2005 | .0688 | .7647 |
| 2006 | .0685 | .7157 |
| 2007 | .0681 | .6700 |
| 2008 | .0677 | .6275 |
| 2009 | .0672 | .5880 |
| 2010 | .0667 | .5513 |

**TABLE 6.4**
**COMPARISON OF RATES FOR TEST**
(2002 mills/kWh)

| Fiscal Year | Discounted Program Case Rate | Discounted 7(b)(2) Case Rate |
|---|---|---|
| 2002 | 28.991 | 23.918 |
| 2003 | 26.477 | 21.721 |
| 2004 | 25.270 | 20.867 |
| 2005 | 23.678 | 19.638 |
| 2006 | 22.125 | 18.485 |
| 2007 | 21.464 | 19.907 |
| 2008 | 19.946 | 19.102 |
| 2009 | 19.026 | 19.270 |
| 2010 | 17.518 | 18.982 |
| Average Rate | 22.7 | 20.2 |
| Difference of Average Rates | 2.5 | |

# 7. BACKCAST OF IOU ASCs, FY 2002-2006

## 7.1 2002 -2006 Backcast Overview

The purpose of this section is to estimate the annual ASC determinations that would have been made had the investor-owned utilities (IOUs) submitted ASC filings with BPA for 2002-2006.

During FY 2002-2006, no ASC filings were made with BPA. Such filings would have been made had BPA and the IOUs not executed REP Settlement Agreements and instead had an active REP. Consequently, annual ASCs must be estimated in order to determine what REP payments the IOUs would have received for this period under an active REP. This section of the Lookback Study will describe how these ASC determinations were made and present the results. Annual ASCs were calculated for Avista, Idaho Power, NorthWestern Energy, PacifiCorp, Portland General Electric, and Puget Sound Energy. Public utilities were not included in this review process for FY 2002-2006.

To estimate these ASCs, a detailed financial cost review was completed of each IOU for 2002-2006. The results of this cost review establish an annual "backcast" ASC determination for each utility. This section will focus on the backcast determinations for FY 2002-2006 only. *See also* Section 11 of this Study.

## 7.2 Backcast ASC Determination Process

"Backcast" is BPA's term for ASCs that BPA would have determined had the REP been operational during the WP-02 rate period. A backcast ASC is based on review and analysis of 2002-2006 FERC Form 1 data. These data were entered into the 1984 ASC Cookbook model to establish estimates of the ASCs for each of the IOUs for the WP-02 rate period.

During the data collection and model input process it was recognized that the existing ASC Cookbook model, based on the 1984 ASC Methodology (ASCM), was outdated. Also, it was found that when data was manually transferred from a specific utility's records to the ASC Cookbook model, input errors resulted in some instances. The ASC Cookbook was updated to reflect new and corrected information.

The 1984 ASCM was applied to all utilities, with exception of not using the jurisdictional approach as the source for data, *i.e.*, data used before a regulatory commission for ratesetting purposes. Instead, cost, revenue, and load data were obtained from FERC's Uniform System of Accounts (Form No. 1 filings) for each IOU. The FERC Form 1 data populated the ASC Cookbook, an Excel-based computer modeling tool. Once populated with a utility's financial data, the ASC Cookbook separates, or "functionalizes," the total costs and revenues into the production, transmission, and distribution functions, *i.e.*, to functions that may be exchanged (exchangeable costs) and to those that may not be exchanged.

The sum of all exchangeable costs is described as Contract System Costs in the 1984 ASCM. The ASC is the result of dividing a utility's Contract System Costs by its Contract System Load, which is the sum of total retail load and distribution losses. The resulting backcast ASC for each of the IOUs is one factor used to determine estimates of REP benefits. The REP benefit determinations are discussed in Section 14.

### 7.3 Data Input for ASCs

The jurisdictional approach was not used in the backcast ASC determinations because the REP settlement agreements did not require utilities to submit ASC filings during FY 2002-2006. To determine costs, revenues, and loads, annual historical data was used that was reported by each IOU through FERC Form 1 filings. When appropriate, a utility's result of operations report was also used. The FERC Form 1 data was downloaded and linked directly to the ASC Cookbook model. This process allowed for the most accurate, straightforward, and efficient data entry to complete the estimates for previous years.

BPA developed backcast ASCs for each year and each IOU using FERC Form 1 data to estimate the costs each utility would have filed pursuant to the 1984 ASC Methodology and their RPSAs.

### 7.4 Backcast ASC Calculation

A backcast ASC calculation is a four step process that includes the following: (1) exchangeable rate base; (2) return on rate base; (3) contract system costs; and (4) the resulting backcast ASC.

#### 7.4.1 Exchangeable Rate Base Calculation

Exchangeable rate base is determined by identifying net production and transmission assets that are functionalized to production and transmission. These assets include total plant investments less depreciation and amortization reserves. The 1984 ASC Methodology specifies which assets are to be functionalized to production and transmission.

#### 7.4.2 Return on Rate Base Calculation

Return on rate base is calculated by multiplying exchangeable rate base by a cost of capital percentage. The 1984 ASCM established that the cost of capital is equal to the weighted cost of debt. The weighted cost of debt was derived by dividing total interest expense by total outstanding debt. Both values are found in the FERC Form 1. Return on rate base is a direct cost that is included in the Contract System Cost.

### 7.4.3 Contract System Costs Calculation

Contract System Costs is determined by accumulating total operating expenses for a utility. Contract System Costs and credits include operation, maintenance, and fuel costs associated with generating resources and transmission plant, purchased power and other power supply expenses, and transmission expenses. In addition, Contract System Costs include administration and general, depreciation and amortization, and taxes. Contract System Costs are reduced by production related to the net disposition of utility plants, revenue from sales for resale, and other miscellaneous revenues. Contract System Costs and related credits are only those that are functionalized to production or transmission.

The Contract System Costs is then determined using the following calculation:

Contract System Costs = (operating costs) – (wholesale market revenues and other revenue credits) + (return on rate base)

### 7.4.4 Contract System Load and Exchange Load

Prior to completing the final step in the ASC rate calculation, it is necessary to determine the Contract System Loads of a utility. Contract System Load is the total consumer end-use load of a utility that is reported in the FERC Form 1. The 1984 ASCM requires that distribution losses be included in Contract System Load. A loss factor of 5 percent was used to increase each utility's end-use load to determine their Contract System Load.

Exchange load was developed from FERC Form 1 reported residential end-use load, plus small farm load where available. Residential end-use load was increased by a 5 percent distribution loss factor to determine each IOU's exchange load.

### 7.4.5 Backcast ASC Calculation

The base ASC determination is calculated by dividing a utility's Contract System Costs by the utility's Contract System Load.

## 7.5 Changes That Were Made to the ASC Cookbook Model

It was recognized that the existing ASC Cookbook model, based on the 1984 ASCM, was outdated. Had the REP been in place during FY 2002-2006, updates would have been completed and any errors would have been corrected in the process of making ASC determinations. For this backcast, the ASC Cookbook was updated and corrected to reflect changed circumstances and information.

The following sections outline both major and minor revisions that are proposed to the 1984 ASC Cookbook model. The revisions include changes in assumptions, addition of new accounts, deletion of out-dated accounts, deletion of repetitive line items, and updates/changes to funtionalizations.

For details to the specific line items, refer to the 1984 ASC Cookbook template published in the WP-07 Final Proposal, WP-07-FS-BPA-05B, and the revised 1984 ASC Cookbook. *See* Lookback Documentation, WP-07-E-BPA-44A, Section 7.

### 7.5.1 Firm Sales for Resale

Firm sales for resale revenues are functionalized to production. It was assumed that a utility's resources were used first to meet its requirements load, and then to support its wholesale marketing activities. In the ASC forecast, the sales for resale credit was reduced to 80 percent of the actual reported amount. For the backcast ASCs, 100 percent of the firm sales for resale actual reported amounts are proposed to be credited in the calculation of the IOUs' ASCs.

### 7.5.2 Other Revenue Accounts, FERC Account Numbers 450-456.1

The "Other Revenue Accounts" are accounts established to record revenues that are not directly tied to the sale of power. The accounts include: Sale of Water/Water Power; Rent from Utility Property, Wheeling Revenue and Other Miscellaneous Revenues. Listed below are the proposed changes to Accounts 450-456.1.

#### 7.5.2.1 Functionalization of Account 453 "Sale of Water/Water Power"

BPA changed the functionalization of Account 453 "Sale of Water/Water Power'' from Direct Production to Direct Distribution. Account 453 includes revenues derived from the sale of water for irrigation, domestic and industrial purposes. Though the revenues might be associated with a hydro facility, the revenues are not directly tied to the generation of power.

#### 7.5.2.2 Functionalization of Account 454 "Rent from Property"

BPA changed the functionalization of Account 454, "Rent from Property" from Direct Production to the Transmission and Distribution (TD) ratio. Account 454 includes the revenue from the rental of utility property. This includes buildings and other assets. However, in the description of this account there are no revenues that are tied directly to generation facilities or the utility's system. The TD ratio is proposed to account for the rental of buildings and property as well as the revenues derived from telecommunication and fiber systems that are attached to the distribution and transmission poles and towers.

#### 7.5.2.3 Functionalization of Account 456 "Other Revenues"

BPA changed the functionalization of account 456 "Other Revenues" from Direct Transmission to production/transmission/distribution/general (PTDG) ratio. FERC has established Account 456.1 to account for wheeling revenues; therefore, the remaining costs in Account 456 are miscellaneous.

#### 7.5.2.4 Functionalization of Account 456.1 "Transmission of Power for Others"

Account 456.1 was established by FERC to account for wheeling revenues. This account continues to use the Direct Transmission functionalization for wheeling revenues.

### 7.5.3 Derivatives

A derivative is a financial instrument whose value depends on some underlying financial asset, commodity index or predefined variable. Some of the main uses of derivative instruments are to fix future prices in the present (forwards and futures), to exchange cash flows or modify asset characteristics (swaps) and to endow the holder with the right, but not the obligation, to engage in a transaction (options).[2] The main types of derivatives used in the utility industry include futures, forwards, options, and swaps associated with the purchase or sale of power and fuel. Utilities are required to book assets and liabilities related to derivatives on their balance sheets.

Derivative accounts were functionalized to Distribution in the WP-07 Final Proposal. In addition, derivatives were discussed the Final WPRDS, WP-07-FS-BPA-05, Section 2.19.1.1.2. BPA is proposing to functionalize derivatives to Production for purposes of the backcast ASCs.

All derivative accounts listed in the FERC System of accounts have been incorporated. These include:

#### 7.5.3.1 Derivative Assets

- Account 175 "Long-Term Portion of Derivative Assets"
- Account 176 "Long-Term Portion of Derivative Assets- Hedges"
- Account 176 "Less: Long-Term Portion of Derivative Assets- Hedges"

[2] Guide to the International Banking Statistics, Page 65. July 2000 - Bank for International Settlements Monetary and Economic Department Basel, Switzerland.

#### 7.5.3.2 Derivative Liabilities

- Account 244 "Long-Term Portion of Derivative Instruments Liabilities"
- Account 245 "Long-Term Portion of Derivative Instruments- Hedges Liabilities"
- Account 245 "Less: Long-Term Portion of Derivative Instruments- Hedges Liabilities"

### 7.5.4 Oregon Public Purpose Charges and Conservation

In 1999, the state of Oregon passed legislation mandating that utility customers be charged three percent of the total retail revenues of electric and gas utilities that operate in Oregon, to be used to develop comprehensive conservation and renewable resource programs. This surcharge, known as the Oregon Public Purpose Charge (OPPC), funds conservation and other renewable projects conducted within the service territories of the applicable utilities. The OPPC effectively replaces the conservation programs within the state of Oregon for Portland General Electric, PacifiCorp (Oregon) and, in 2006, Idaho Power.

BPA proposes to include the OPPC as a conservation cost of the Oregon utilities for purposes of determining the backcast ASC.

Without accounting data from the IOUs or information from the Oregon Public Utility Commission, it is very difficult to determine how this charge would be capitalized and amortized overtime. Therefore, BPA proposes to treat this charge as an expense each year.

Under the 1984 ASC Methodology, conservation is generally functionalized to production. However, the 1984 ASC Methodology specifies that advertising costs and costs associated with model conservation be excluded. BPA has limited information about what portion of the OPPC funds are used for these non-exchangeable purposes. To account for costs such as advertising and model conservation, 70 percent of the costs will be functionalized to production; the remaining 30 percent functionalized to distribution.

### 7.5.5 Conservation Costs

The FERC Form 1 does not have adequate detail to show the allocation of costs associated with the various types of conservation. Therefore, to be consistent with the treatment of the OPPC discussed above, BPA is proposing to use a new functionalization ratio called "direct conservation" or DIR-C. This functionalization code allocates 70 percent of conservation cost to production and 30 percent to distribution.

### 7.5.6 Common Plant

Common utility plant is property plant and equipment that is shared between the electric and retail gas operations of a utility. As a shared plant, there needs to be a line that is discernable between the electric and gas operations of the utility in order to calculate the exchangeable electric operations.

BPA is proposing to functionalize the common utility plant using the Production/Transmission/Distribution (PTD) ratio. The revised 1984 ASC Cookbook includes the Accumulated Provision for Depreciation, Amortization, & Depletion of Common Plant in the Account 108 "Depreciation Reserve".

### 7.5.7 Acquisition Adjustments

Acquisition Adjustments represent the difference between the book value of acquired utility plant and the purchase price of the acquisition of the utility plant.

Acquisition adjustments are proposed to be functionalized to production. This treatment recognizes that the regional utilities are investing in generation projects by either building new plants or buying shares of new or established generation plants.

### 7.5.8 Functionalization of Property Taxes

BPA proposes to change the functionalization of property taxes that are assessed against production assets that are outside a utility's service territory. Property taxes are generally functionalized using the production/transmission/distribution/general (PTDG) ratio. Property taxes in states where the utility has service territory continue to be functionalized by PTDG. For property taxes in states where the utility has a generating facility that is outside the service territory, the proposed functionalization is to Direct Production. An example of this is the Colstrip power plant, located in Montana, where the participating utilities do not have service territory in Montana, yet include Montana property taxes on their FERC Form 1.

The FERC Form 1 of each utility was reviewed to identify in which states there was retail service territory. In addition, the property taxes of each utility were reviewed to determine which property taxes were paid to states outside their service territory. The production assets of the utilities were then reviewed to determine if the taxes outside of their service territory were in states where the utility has a production plant.

## 7.6 Line Item Changes

The 1984 ASC Cookbook was revised to conform to the FERC Form 1 line items. Listed below are changes to the ASC Cookbook that have not been discussed above.

### 7.6.1 Deletions of Line Items

The following line items are proposed to be deleted:

#### 7.6.1.1 Schedule 1: Rate Base

- Duplicated lines for "Other Production Plant", Accounts 340-346

- All lines within General plant, that has the 10%TD functionalization
- Duplicated lines items for "Other Production" in the Amortization and Depreciation reserve section, Account 108
- "Other Transmission Plant" line items in the Amortization and Depreciation reserve section, Account 108
- "Other Amortization" in the Amortization and Depreciation reserve section, Account 108
- "Amort. Reserve" in the Amortization and Depreciation reserve section, Account 111
- "Investments", Account 123
- "Weatherization Investment" within the Deferred Debits, this is included within Regulatory assets.
- "Interest and Dividend receivable" within the Deferred Debits section
- "Other Credits" within the Deferred Credits section

#### 7.6.1.2 Schedule 3: Operating Expenses

- All lines that are "Other Prod" within Production Expenses
- All lines that are "Other Trans" within Production Expenses
- All lines that are "Other Dist" within Production Expenses
- All lines within Administration & General Expense section, with the 10% TD functionalization
- All lines that are "Other A&G" within Administration & General Expense section
- "Other Depreciation Exp" within the Depreciation and Amortization Expenses
- "Amort. of Limited Term Plant" within the Depreciation and Amortization Expenses
- "Amort. of Prop. Losses" within the Depreciation and Amortization Expenses
- "Amort. of Regulatory Assets" within the Depreciation and Amortization Expenses
- All "Other Amort." within the Depreciation and Amortization Expenses

- "In-lieu Taxes". This was removed as a line item as well as the section that calculated this line item
- "Non-Firm Sales for Resale" within the Other Included Item section
- "Billing Credits" in the Other Revenue Section
- All "Other Revenue" in the Other Revenue Section

### 7.6.2 Addition of Line Items

The following line items are proposed to be added:

#### 7.6.2.1 Schedule 1: Rate Base

- "Accum. Prov for Depr, Amort, and Depl. Commn Plt" Line item is discussed above and functionalized using PTDG ratio
- "Accum. Prov for Depr, Amort, and Depl.: Other Utl Plt: Electric" Functionalized using PTD ratio
- "Amort. of Plant Acquisition Adjustment (Electric)" Functionalized to Production
- "(Utility Plant) In Service (Classified) Common," Discussed above
- "Other Materials and Supplies" Account 156 Functionalized on the PTDG ratio
- "Stores Expense Undistributed" Account 163 Functionalized on the PTD ratio
- "Preliminary Survey and Investigation Charges Electric" Account 183 Functionalized to Distribution
- "Preliminary Natural Gas Survey and Investigation Charges" Account 183.1 Functionalized to Distribution
- "Other Preliminary Survey and Investigation Charges" Account 183.2 Functionalized to Distribution
- "Temporary Facilities" Account 185 Functionalized with the PTDG ratio

- "Deferred Losses from Disposition of Utility Plant" Account 187 Functionalized with the PTD ratio
- "Research, Development and Demonstration Expenditures" Account 188 Functionalized to Distribution
- "Unamortized Loss on Reacquired Debt" Account 189 Functionalized with the PTDG ratio
- "Accumulated Deferred Income Taxes" Account 190 Functionalized to Distribution
- "Unrecovered Purchased Gas Costs" Account 191 Functionalized to Production
- "Other Regulatory Liabilities" Functionalized using Direct Analysis

#### 7.6.2.2 Schedule 3: Operating Expenses

- "BPA REP Reversal" Functionalized to Production
- "Oregon Public Purposes Charge" Functionalized using the DIR-C functionalization ratio as discussed above
- "Common Plant – Electric" within the Depreciation and Amortization Section Discussed above
- Renamed Account 411.6 located in the Other Included Items to "(Less) Gain from Disp. of Plant"
- Renamed Account 447 located in Sales for Resale section to "Sales for Resale"
- "Revenues from Transmission of Electricity of Other" Account 456.1 Functionalized to Transmission as discussed above
- "Regional Control Service Revenues" Account 457.1 Functionalized to Transmission
- "Miscellaneous Revenues" Account 457.2 Functionalized to Transmission

### 7.6.3 Functionalization Changes

BPA proposes to make the changes described below to the functionalization of the following accounts in addition to those discussed above. The changes are due to error corrections, general updates, and changes in assumption based on new or better information. The abbreviations used in the descriptions are as follows:

| | |
|---|---|
| Functionalized to Production (direct): | DIR-P |
| Functionalized to Transmission (direct): | DIR-D |
| Functionalized to Distribution (direct): | DIR-D |
| Functionalized to General: | G |
| Production, Transmission, and Distribution (ratio): | PTD |

#### 7.6.3.1 Schedule 1: Rate Base

- Account 338 "Miscellaneous Equipment" Change Functionalization from DIR-D to PTD
- Account 105 "Plant Held for Future Use" Change Functionalization from PTD to PTDG
- Account 154 "Plant Materials and Operating Supplies" Change Functionalization from TDG to PTD
- Account 184 "Clearing Accounts" Change Functionalization from Labor to DIR-D
- Account 186 "Miscellaneous Deferred Debits" Change Functionalization from Labor to Direct Analysis
- Account 256 "Deferred Gains from Disposition of Utility Plant" Change Functionalization from TDG to PTD
- Account 253 "Other Deferred Credits" Change Functionalization from DIR-D to Direct Analysis

#### 7.6.3.2 Schedule 2: Operating Expenses

- Account 922 "(Less) Administration Expenses Transferred Credit" Change Functionalization from Labor to PTD

- Account 923 “Outside Services Employed” Change Functionalization from Labor to PTD
- Account 929 “(Less) Duplicate Charges – Credit” Change Functionalization from Labor to PTDG
- Account 930.2 “Miscellaneous General Expenses” Change Functionalization from DIR-D to PTD
- Account 931 “Rents” Change Functionalization from DIR-D to PTD

### 7.6.4 PacifiCorp Inter-Jurisdictional Cost Allocation

As stated above, PacifiCorp’s costs are allocated to PNW states Idaho, Oregon, and Washington. This reflects how PacifiCorp would have filed for ASCs if there was an active REP. First, PacifiCorp’s total utility cost data from the FERC Form 1 was entered into the ASC Cookbook model. To allocate PacifiCorp’s total system to the identified PNW states, PacifiCorp’s costs were allocated based on the Inter-Jurisdictional Cost Allocation System developed jointly by most of the state commissions that regulate PacifiCorp. This system allocates PacifiCorp’s total electric operations proportionately to each state in which it has regulated service territory.

PacifiCorp provided the annual state allocation factors in an electronic form. In addition, BPA used PacifiCorp’s Oregon Jurisdiction Results of Operations filings to the Oregon Public Utility Commission for 2002, 2004, and 2006. The Results of Operations filings were used to develop allocation factors for rate base and cost that were directly allocated to each state. The 2003 allocation factors for direct allocation to each state were developed from the 2002 Results of Operations filing. This process was replicated for 2005. In addition, the Results of Operations filings were used to match the allocation factors that were provided by PacifiCorp to the corresponding accounts in the ASC Cookbook model. The total costs in each account were then multiplied by the individual state allocation factors to produce the cost for Oregon, Washington and Idaho.

### 7.6.5 Reversal of Purchase Power Expense

Puget Sound and PacifiCorp recorded a negative purchase power expense in their FERC Form 1 to account for the benefits paid by BPA under the REP Settlements. BPA removed this negative entry.

Portland General included the BPA power sale in its power purchases at BPA's RL rate. We removed the power purchase at the RL rate and replaced it with purchases at market rates. The effect of this adjustment is to increase Portland General's cost of purchase power.

## 7.7 Summary of Backcast ASCs for FY 2002-2006

Table 7.1 summarizes the backcast ASC determinations by utility for FY 2002-2006.

**TABLE 7**
**Backcast ASCs – FY 2002-2006**
($/MWh)

| | 2002 | 2003 | 2004 | 2005 | 2006 |
|---|---|---|---|---|---|
| Avista | 44.38 | 44.54 | 45.77 | 42.39 | 44.47 |
| Idaho Power | 44.66 | 37.52 | 34.21 | 33.27 | 28.36 |
| NorthWestern Energy | 46.99 | 46.99 | 50.43 | 47.50 | 52.62 |
| PacifiCorp (regional) | 37.65 | 36.80 | 39.49 | 40.74 | 40.91 |
| Portland General | 52.54 | 47.16 | 44.30 | 46.99 | 49.72 |
| Puget Sound | 48.05 | 45.41 | 46.50 | 50.21 | 55.13 |

# Table 7.1
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | AVISTA |
| Date Filed: | 7/2/2003 |
| Year/Quarter: | **2002/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 1:*** *Plant Investment / Rate Base / Rate of Return* | | | | |
| Total Intanglibe Plant | 26,239,075 | 11,203,872 | 4,466,267 | 10,568,936 |
| Total Production Plant | 740,735,723 | 740,735,723 | 0 | 0 |
| Total Transmission Plant | 295,283,980 | 0 | 295,283,980 | 0 |
| Total Distribution Plant | 698,757,399 | 0 | 0 | 698,757,399 |
| Total General Plant | 48,474,712 | 10,600,221 | 11,244,331 | 26,630,160 |
| **Total Electric Plant In-Service** | 1,809,490,889 | 762,539,816 | 310,994,579 | 735,956,494 |
| **LESS:** | | | | |
| **Total Depreciation and Amortization** | 639,181,621 | 281,403,340 | 120,865,135 | 236,913,146 |
| **Total Net Plant** | 1,170,309,268 | 481,136,476 | 190,129,444 | 499,043,348 |
| *(Total Electric Plant In-Service) - (Total Depreciation & Amortization)* | | | | |
| **Assets and Other Debits (Comparative Balance Sheet)** | | | | |
| Cash Working Capital | 29,849,502 | 19,832,008 | 2,447,511 | 7,569,983 |
| Total Utility Plant | 119,728,736 | 44,900,684 | 17,899,032 | 56,929,020 |
| Total Other Property and Investments | 46,498,833 | 0 | 0 | 46,498,833 |
| Total Current and Accrued Assets | 75,443,963 | 68,647,708 | 2,018,855 | 4,777,400 |
| Total Deferred Debits | 443,938,853 | 210,252,910 | 10,306,674 | 223,379,269 |
| **Total Assets and Other Debits** | 715,459,887 | 343,633,311 | 32,672,072 | 339,154,504 |
| **LESS:** | | | | |
| **Liabilities and Other Credits (Comparative Balance Sheet)** | | | | |
| Total Other Noncurrent Liablities | 0 | 0 | 0 | 0 |
| Total Current and Accrued Liabilities | 50,057,633 | 50,057,633 | 0 | 0 |
| Total Deferred Credtis | 535,788,341 | 34,996,533 | 3,899,825 | 496,891,983 |
| **Total Liabilities and Other Credits** | 585,845,974 | 85,054,166 | 3,899,825 | 496,891,983 |
| **Total Rate Base** | 1,299,923,181 | 1,299,923,181 | 1,299,923,181 | 1,299,923,181 |
| *(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)* | | | | |

***Schedule 2: Weighted Average Cost of Long Term Debt***

| | |
|---|---|
| Long Term Debt | 1,105,078,874 |
| Interest for Year | 93,183,757 |
| **Rate of Return** | 8.43% |

*(Interest/Long Term Debt)*

# Table 7.1
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | AVISTA |
| Date Filed: | 7/2/2003 |
| Year/Quarter: | **2002/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 3: Expenses*** | | | | |
| Total Production Expense | 276,115,311 | 276,115,311 | 0 | 0 |
| Total Transmission Expense | 13,592,302 | 0 | 13,592,302 | 0 |
| Total Distribution Expense | 14,320,185 | 0 | 0 | 14,320,185 |
| Total Customer and Sales Expenses | 23,375,746 | 0 | 0 | 23,375,746 |
| Total Administration and General Expenses | 46,173,337 | 17,321,619 | 5,987,786 | 22,863,931 |
| **Total Operations and Maintenance** | 373,576,881 | 293,436,930 | 19,580,088 | 60,559,862 |
| **Total Depreciation and Amortization** | 53,677,906 | 24,812,307 | 9,064,394 | 19,801,205 |
| ***Schedule 3A Items: Taxes*** | | | | |
| **Taxes Accrued, Prepaid, and Charged During Year** | | | | |
| Total Federal | 5,859,037 | 3,087,798 | 897,625 | 1,873,615 |
| Total State | 49,871,419 | 12,215,733 | 2,591,720 | 35,063,966 |
| Total County and Municipal | 15,957,107 | 6,318,154 | 1,836,691 | 7,802,262 |
| **Total Taxes** | 71,687,563 | 21,621,685 | 5,326,036 | 44,739,842 |
| ***Schedule 3B Items: Other Included Items*** | | | | |
| Total Disposition of Plant | 0 | 0 | 0 | 0 |
| Total Sales from Resale | 64,082,272 | 64,082,272 | 0 | 0 |
| Total Other Revenues | 55,491,115 | 17,577,365 | 18,957,278 | 18,956,473 |
| **Total Other Included Items** | 119,573,387 | 81,659,637 | 18,957,278 | 18,956,473 |
| ***Schedule 4: Average System Costs*** | | | | |
| **Total Operating Expenses** *(Total O&M + Total Depreciation & Amortization + Total Taxes - Total Other Included Items)* | 379,368,963 | 258,211,286 | 15,013,240 | 106,144,437 |
| **Return from Rate Base** *(Total Rate Base * Rate of Return)* | 109,613,647 | 62,375,168 | 18,458,485 | 28,779,994 |
| **Total Cost** *(Total Operating Expenses + Return from Rate Base)* | 488,982,610 | 320,586,454 | 33,471,725 | 134,924,431 |

| | |
|---|---|
| Total Load (MWh) | 7,598,029 |
| 5% Distribution Losses (MWh) | 379,901 |
| **Average System Cost ($/MWh)** | **44.38** |

*(Total Production and Transmission Costs) / (Total Load + Distribution Losses)*

# Table 7.1 continued
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | AVISTA |
| Date Filed: | 4/30/2004 |
| Year/Quarter: | **2003/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 1:*** *Plant Investment / Rate Base / Rate of Return* | | | | |
| Total Intanglibe Plant | 26,484,820 | 12,001,902 | 4,290,864 | 10,192,055 |
| Total Production Plant | 852,627,548 | 852,627,548 | 0 | 0 |
| Total Transmission Plant | 304,827,401 | 0 | 304,827,401 | 0 |
| Total Distribution Plant | 724,054,166 | 0 | 0 | 724,054,166 |
| Total General Plant | 52,183,500 | 12,390,123 | 11,779,717 | 28,013,660 |
| **Total Electric Plant In-Service** | 1,960,177,435 | 877,019,573 | 320,897,982 | 762,259,881 |
| **LESS:** | | | | |
| **Total Depreciation and Amortization** | 686,989,565 | 305,818,974 | 128,271,374 | 252,899,217 |
| **Total Net Plant** | 1,273,187,870 | 571,200,599 | 192,626,608 | 509,360,663 |
| *(Total Electric Plant In-Service) - (Total Depreciation & Amortization)* | | | | |
| **Assets and Other Debits (Comparative Balance Sheet)** | | | | |
| Cash Working Capital | 30,803,571 | 20,321,811 | 2,600,835 | 7,880,925 |
| Total Utility Plant | 156,734,762 | 50,946,291 | 18,214,079 | 87,574,392 |
| Total Other Property and Investments | 55,738,128 | 0 | 0 | 55,738,128 |
| Total Current and Accrued Assets | 51,989,612 | 46,469,555 | 1,635,431 | 3,884,626 |
| Total Deferred Debits | 438,013,241 | 213,125,605 | 9,683,157 | 215,204,479 |
| **Total Assets and Other Debits** | 733,279,314 | 330,863,262 | 32,133,502 | 370,282,551 |
| **LESS:** | | | | |
| **Liabilities and Other Credits (Comparative Balance Sheet)** | | | | |
| Total Other Noncurrent Liablities | 0 | 0 | 0 | 0 |
| Total Current and Accrued Liabilities | 36,057,271 | 36,057,271 | 0 | 0 |
| Total Deferred Credtis | 566,645,699 | 29,741,678 | 3,882,510 | 533,021,511 |
| **Total Liabilities and Other Credits** | 602,702,970 | 65,798,949 | 3,882,510 | 533,021,511 |
| **Total Rate Base** | 1,403,764,214 | 836,264,912 | 220,877,599 | 346,621,703 |
| *(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)* | | | | |

***Schedule 2: Weighted Average Cost of Long Term Debt***

| | |
|---|---|
| Long Term Debt | 1,122,669,487 |
| Interest for Year | 82,856,279 |
| **Rate of Return** | 7.38% |

*(Interest/Long Term Debt)*

# Table 7.1 continued
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | AVISTA |
| Date Filed: | 4/30/2004 |
| Year/Quarter: | **2003/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 3: Expenses*** | | | | |
| Total Production Expense | 329,682,924 | 329,682,924 | 0 | 0 |
| Total Transmission Expense | 14,989,464 | 0 | 14,989,464 | 0 |
| Total Distribution Expense | 16,539,116 | 0 | 0 | 16,539,116 |
| Total Customer and Sales Expenses | 23,555,750 | 0 | 0 | 23,555,750 |
| Total Administration and General Expenses | 47,379,256 | 18,609,502 | 5,817,216 | 22,952,538 |
| **Total Operations and Maintenance** | 432,146,510 | 348,292,426 | 20,806,680 | 63,047,404 |
| **Total Depreciation and Amortization** | 57,368,348 | 28,070,204 | 9,192,603 | 20,105,541 |
| ***Schedule 3A Items: Taxes*** | | | | |
| **Taxes Accrued, Prepaid, and Charged During Year** | | | | |
| Total Federal | 3,352,764 | 3,701,840 | 999,866 | (1,348,942) |
| Total State | 47,296,247 | 13,513,859 | 2,729,452 | 31,052,936 |
| Total County and Municipal | 15,105,721 | 6,085,631 | 1,643,728 | 7,376,362 |
| **Total Taxes** | 65,754,732 | 23,301,330 | 5,373,045 | 37,080,357 |
| ***Schedule 3B Items: Other Included Items*** | | | | |
| Total Disposition of Plant | 0 | 0 | 0 | 0 |
| Total Sales from Resale | 80,710,417 | 80,710,417 | 0 | 0 |
| Total Other Revenues | 87,425,855 | 32,922,947 | 23,321,135 | 31,181,774 |
| **Total Other Included Items** | 168,136,272 | 113,633,364 | 23,321,135 | 31,181,774 |
| ***Schedule 4: Average System Costs*** | | | | |
| **Total Operating Expenses** | 387,133,318 | 286,030,597 | 12,051,193 | 89,051,528 |
| *(Total O&M + Total Depreciation & Amortization + Total Taxes - Total Other Included Items)* | | | | |
| **Return from Rate Base** | 103,601,889 | 61,718,787 | 16,301,410 | 25,581,692 |
| *(Total Rate Base * Rate of Return)* | | | | |
| **Total Cost** | 490,735,207 | 347,749,384 | 28,352,603 | 114,633,219 |
| *(Total Operating Expenses + Return from Rate Base)* | | | | |

| | |
|---|---|
| Total Load (MWh) | 8,041,166 |
| 5% Distribution Losses (MWh) | 402,058 |
| **Average System Cost ($/MWh)** | **44.54** |

*(Total Production and Transmission Costs) / (Total Load + Distribution Losses)*

# Table 7.1 continued
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | AVISTA |
| Date Filed: | 4/25/2005 |
| Year/Quarter: | 2004/Q4 |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 1:*** *Plant Investment / Rate Base / Rate of Return* | | | | |
| Total Intanglibe Plant | 27,037,661 | 11,902,632 | 4,654,029 | 10,480,999 |
| Total Production Plant | 863,539,966 | 863,539,966 | 0 | 0 |
| Total Transmission Plant | 337,651,373 | 0 | 337,651,373 | 0 |
| Total Distribution Plant | 760,400,014 | 0 | 0 | 760,400,014 |
| Total General Plant | 53,766,005 | 12,894,175 | 12,558,274 | 28,313,556 |
| **Total Electric Plant In-Service** | 2,042,395,019 | 888,336,774 | 354,863,676 | 799,194,569 |
| **LESS:** | | | | |
| **Total Depreciation and Amortization** | 715,663,333 | 316,344,244 | 134,349,766 | 264,969,322 |
| **Total Net Plant** | 1,326,731,686 | 571,992,529 | 220,513,909 | 534,225,247 |
| *(Total Electric Plant In-Service) - (Total Depreciation & Amortization)* | | | | |
| **Assets and Other Debits (Comparative Balance Sheet)** | | | | |
| Cash Working Capital | 32,935,455 | 21,395,630 | 2,839,136 | 8,700,689 |
| Total Utility Plant | 129,233,967 | 39,962,528 | 15,625,684 | 73,645,755 |
| Total Other Property and Investments | 93,007,135 | 55,824,772 | 0 | 37,182,363 |
| Total Current and Accrued Assets | 27,952,949 | 20,281,539 | 2,358,963 | 5,312,447 |
| Total Deferred Debits | 428,982,406 | 193,721,137 | 11,148,765 | 224,112,504 |
| **Total Assets and Other Debits** | 712,111,912 | 331,185,606 | 31,972,548 | 348,953,759 |
| **LESS:** | | | | |
| **Liabilities and Other Credits (Comparative Balance Sheet)** | | | | |
| Total Other Noncurrent Liablities | 39,971,987 | 39,971,987 | 0 | 0 |
| Total Current and Accrued Liabilities | 5,712,950 | 5,712,950 | 0 | 0 |
| Total Deferred Credtis | 601,471,693 | 44,200,658 | 2,964,602 | 554,306,433 |
| **Total Liabilities and Other Credits** | 647,156,630 | 647,156,630 | 647,156,630 | 647,156,630 |
| **Total Rate Base** | 1,391,686,968 | 810,029,447 | 248,245,958 | 333,411,563 |
| *(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)* | | | | |

***Schedule 2: Weighted Average Cost of Long Term Debt***

| | |
|---|---|
| Long Term Debt | 1,133,530,068 |
| Interest for Year | 79,197,611 |
| **Rate of Return** | 6.99% |

*(Interest/Long Term Debt)*

# Table 7.1 continued
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | AVISTA |
| Date Filed: | 4/25/2005 |
| Year/Quarter: | **2004/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 3: Expenses*** | | | | |
| Total Production Expense | 364,036,052 | 364,036,052 | 0 | 0 |
| Total Transmission Expense | 16,115,328 | 0 | 16,115,328 | 0 |
| Total Distribution Expense | 19,108,033 | 0 | 0 | 19,108,033 |
| Total Customer and Sales Expenses | 25,629,327 | 0 | 0 | 25,629,327 |
| Total Administration and General Expenses | 51,165,545 | 19,699,628 | 6,597,762 | 24,868,155 |
| **Total Operations and Maintenance** | 476,054,285 | 383,735,680 | 22,713,090 | 69,605,515 |
| **Total Depreciation and Amortization** | 57,428,642 | 28,615,880 | 9,400,588 | 19,412,174 |
| ***Schedule 3A Items: Taxes*** | | | | |
| **Taxes Accrued, Prepaid, and Charged During Year** | | | | |
| Total Federal | 13,919,572 | 3,143,646 | 903,563 | 9,872,363 |
| Total State | 46,910,425 | 13,372,538 | 2,746,405 | 30,791,482 |
| Total County and Municipal | 16,051,765 | 6,458,245 | 1,856,263 | 7,737,257 |
| **Total Taxes** | 76,881,762 | 22,974,429 | 5,506,231 | 48,401,102 |
| ***Schedule 3B Items: Other Included Items*** | | | | |
| Total Disposition of Plant | 0 | 0 | 0 | 0 |
| Total Sales from Resale | 89,993,250 | 89,993,250 | 0 | 0 |
| Total Other Revenues | 82,389,299 | 28,407,430 | 25,957,919 | 28,023,951 |
| **Total Other Included Items** | 172,382,549 | 118,400,680 | 25,957,919 | 28,023,951 |
| ***Schedule 4: Average System Costs*** | | | | |
| **Total Operating Expenses** | 437,982,140 | 316,925,310 | 11,661,990 | 109,394,840 |
| *(Total O&M + Total Depreciation & Amortization + Total Taxes - Total Other Included Items)* | | | | |
| **Return from Rate Base** | 97,234,547 | 56,595,232 | 17,344,478 | 23,294,838 |
| *(Total Rate Base * Rate of Return)* | | | | |
| **Total Cost** | 535,216,687 | 373,520,542 | 29,006,467 | 132,689,678 |
| *(Total Operating Expenses + Return from Rate Base)* | | | | |

| | |
|---|---|
| Total Load (MWh) | 8,376,616 |
| 5% Distribution Losses (MWh) | 418,831 |
| **Average System Cost ($/MWh)** | **45.77** |

*(Total Production and Transmission Costs) / (Total Load + Distribution Losses)*

# Table 7.1 continued
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | AVISTA |
| Date Filed: | 4/17/2006 |
| Year/Quarter: | 2005/Q4 |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 1:*** *Plant Investment / Rate Base / Rate of Return* | | | | |
| Total Intanglibe Plant | 27,115,071 | 12,474,446 | 4,663,598 | 9,977,027 |
| Total Production Plant | 988,538,283 | 988,538,283 | 0 | 0 |
| Total Transmission Plant | 369,567,144 | 0 | 369,567,144 | 0 |
| Total Distribution Plant | 790,630,169 | 0 | 0 | 790,630,169 |
| Total General Plant | 60,419,320 | 16,008,598 | 14,135,365 | 30,275,356 |
| **Total Electric Plant In-Service** | 2,236,269,987 | 1,017,021,327 | 388,366,107 | 830,882,552 |
| **LESS:** | | | | |
| **Total Depreciation and Amortization** | 761,957,388 | 340,625,585 | 143,321,571 | 278,010,232 |
| **Total Net Plant** | 1,474,312,599 | 676,395,742 | 245,044,537 | 552,872,320 |
| *(Total Electric Plant In-Service) - (Total Depreciation & Amortization)* | | | | |
| **Assets and Other Debits (Comparative Balance Sheet)** | | | | |
| Cash Working Capital | 26,756,301 | 15,089,003 | 2,855,729 | 8,811,569 |
| Total Utility Plant | 159,863,306 | 54,108,289 | 20,228,499 | 85,526,517 |
| Total Other Property and Investments | 80,432,811 | 46,731,530 | 0 | 33,701,281 |
| Total Current and Accrued Assets | 89,017,914 | 80,513,020 | 2,709,133 | 5,795,760 |
| Total Deferred Debits | 403,526,254 | 235,705,916 | 23,361,156 | 144,459,182 |
| **Total Assets and Other Debits** | 759,596,586 | 432,147,758 | 49,154,518 | 278,294,309 |
| **LESS:** | | | | |
| **Liabilities and Other Credits (Comparative Balance Sheet)** | | | | |
| Total Other Noncurrent Liablities | 10,044,751 | 10,044,751 | 0 | 0 |
| Total Current and Accrued Liabilities | 3,446,699 | 3,446,699 | 0 | 0 |
| Total Deferred Credtis | 675,181,617 | 130,332,756 | 4,825,347 | 540,023,514 |
| **Total Liabilities and Other Credits** | 688,673,067 | 143,824,206 | 4,825,347 | 540,023,514 |
| **Total Rate Base** | 1,545,236,118 | 964,719,295 | 289,373,708 | 291,143,115 |
| *(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)* | | | | |

***Schedule 2: Weighted Average Cost of Long Term Debt***

| | |
|---|---|
| Long Term Debt | 1,225,824,323 |
| Interest for Year | 80,470,939 |
| **Rate of Return** | 6.56% |

*(Interest/Long Term Debt)*

# Table 7.1 continued
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | AVISTA |
| Date Filed: | 4/17/2006 |
| Year/Quarter: | **2005/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 3: Expenses*** | | | | |
| Total Production Expense | 452,344,552 | 452,344,552 | 0 | 0 |
| Total Transmission Expense | 16,327,683 | 0 | 16,327,683 | 0 |
| Total Distribution Expense | 21,239,624 | 0 | 0 | 21,239,624 |
| Total Customer and Sales Expenses | 24,680,467 | 0 | 0 | 24,680,467 |
| Total Administration and General Expenses | 50,834,871 | 19,744,261 | 6,518,151 | 24,572,458 |
| **Total Operations and Maintenance** | 565,427,197 | 472,088,813 | 22,845,834 | 70,492,549 |
| **Total Depreciation and Amortization** | 64,877,706 | 33,393,276 | 10,467,386 | 21,017,044 |
| ***Schedule 3A Items: Taxes*** | | | | |
| **Taxes Accrued, Prepaid, and Charged During Year** | | | | |
| Total Federal | 31,348,483 | 3,127,687 | 902,162 | 27,318,634 |
| Total State | 67,483,947 | 14,516,937 | 2,840,284 | 50,126,726 |
| Total County and Municipal | 21,349 | 0 | 0 | 21,349 |
| **Total Taxes** | 98,853,779 | 17,644,624 | 3,742,445 | 77,466,709 |
| ***Schedule 3B Items: Other Included Items*** | | | | |
| Total Disposition of Plant | 0 | 0 | 0 | 0 |
| Total Sales from Resale | 221,803,806 | 221,803,806 | 0 | 0 |
| Total Other Revenues | 60,058,249 | 21,021,843 | 19,457,021 | 19,579,385 |
| **Total Other Included Items** | 281,862,055 | 242,825,649 | 19,457,021 | 19,579,385 |
| ***Schedule 4: Average System Costs*** | | | | |
| **Total Operating Expenses** | 447,296,627 | 280,301,065 | 17,598,645 | 149,396,917 |
| *(Total O&M + Total Depreciation & Amortization + Total Taxes - Total Other Included Items)* | | | | |
| **Return from Rate Base** | 101,439,170 | 63,330,337 | 18,996,339 | 19,112,494 |
| *(Total Rate Base * Rate of Return)* | | | | |
| **Total Cost** | 548,735,797 | 343,631,402 | 36,594,984 | 168,509,411 |
| *(Total Operating Expenses + Return from Rate Base)* | | | | |

| | |
|---|---|
| Total Load (MWh) | 8,542,674 |
| 5% Distribution Losses (MWh) | 427,134 |
| **Average System Cost ($/MWh)** | **42.39** |

*(Total Production and Transmission Costs) / (Total Load + Distribution Losses)*

# Table 7.1 continued
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | AVISTA |
| Date Filed: | 4/18/2007 |
| Year/Quarter: | **2006/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 1:*** *Plant Investment / Rate Base / Rate of Return* | | | | |
| Total Intanglibe Plant | 19,679,401 | 8,840,788 | 3,421,380 | 7,417,233 |
| Total Production Plant | 991,794,149 | 991,794,149 | 0 | 0 |
| Total Transmission Plant | 383,823,745 | 0 | 383,823,745 | 0 |
| Total Distribution Plant | 832,094,240 | 0 | 0 | 832,094,240 |
| Total General Plant | 64,737,335 | 16,517,699 | 15,210,483 | 33,009,153 |
| **Total Electric Plant In-Service** | 2,292,128,870 | 1,017,152,636 | 402,455,607 | 872,520,627 |
| **LESS:** | | | | |
| **Total Depreciation and Amortization** | 801,728,444 | 362,220,710 | 151,541,818 | 287,965,916 |
| **Total Net Plant** | 1,490,400,426 | 654,931,926 | 250,913,789 | 584,554,711 |
| *(Total Electric Plant In-Service) - (Total Depreciation & Amortization)* | | | | |
| **Assets and Other Debits (Comparative Balance Sheet)** | | | | |
| Cash Working Capital | 29,680,030 | 17,456,911 | 3,282,132 | 8,940,988 |
| Total Utility Plant | 166,858,770 | 40,781,026 | 15,782,233 | 110,295,511 |
| Total Other Property and Investments | 56,740,866 | 25,574,531 | 0 | 31,166,335 |
| Total Current and Accrued Assets | 33,437,261 | 22,153,845 | 3,561,789 | 7,721,627 |
| Total Deferred Debits | 484,199,368 | 219,974,498 | 16,615,711 | 247,609,159 |
| **Total Assets and Other Debits** | 770,916,295 | 325,940,811 | 39,241,865 | 405,733,619 |
| **LESS:** | | | | |
| **Liabilities and Other Credits (Comparative Balance Sheet)** | | | | |
| Total Other Noncurrent Liablities | 15,318,835 | 15,318,835 | 0 | 0 |
| Total Current and Accrued Liabilities | 73,478,456 | 73,478,456 | 0 | 0 |
| Total Deferred Credtis | 576,833,230 | 26,498,603 | 2,965,748 | 547,368,880 |
| **Total Liabilities and Other Credits** | 665,630,521 | 115,295,894 | 2,965,748 | 547,368,880 |
| **Total Rate Base** | 1,595,686,200 | 843,691,533 | 277,487,430 | 449,764,914 |
| *(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)* | | | | |

### *Schedule 2: Weighted Average Cost of Long Term Debt*

| | |
|---|---|
| Long Term Debt | 1,116,000,333 |
| Interest for Year | 85,054,979 |
| **Rate of Return** | 7.62% |

*(Interest/Long Term Debt)*

# Table 7.1 continued
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | AVISTA |
| Date Filed: | 4/18/2007 |
| Year/Quarter: | **2006/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 3: Expenses*** | | | | |
| Total Production Expense | 431,008,791 | 431,008,791 | 0 | 0 |
| Total Transmission Expense | 19,547,280 | 0 | 19,547,280 | 0 |
| Total Distribution Expense | 22,569,058 | 0 | 0 | 22,569,058 |
| Total Customer and Sales Expenses | 25,860,122 | 0 | 0 | 25,860,122 |
| Total Administration and General Expenses | 49,517,622 | 19,709,124 | 6,709,778 | 23,098,720 |
| **Total Operations and Maintenance** | 548,502,873 | 450,717,915 | 26,257,058 | 71,527,900 |
| **Total Depreciation and Amortization** | 67,390,752 | 34,645,027 | 11,018,514 | 21,727,211 |
| ***Schedule 3A Items: Taxes*** | | | | |
| **Taxes Accrued, Prepaid, and Charged During Year** | | | | |
| Total Federal | 55,538,224 | 3,163,380 | 939,446 | 51,435,398 |
| Total State | 76,261,914 | 13,368,840 | 2,668,025 | 60,225,049 |
| Total County and Municipal | 11,907 | 0 | 0 | 11,907 |
| **Total Taxes** | 131,812,045 | 16,532,220 | 3,607,471 | 111,672,354 |
| ***Schedule 3B Items: Other Included Items*** | | | | |
| Total Disposition of Plant | 0 | 0 | 0 | 0 |
| Total Sales from Resale | 175,572,595 | 175,572,595 | 0 | 0 |
| Total Other Revenues | 66,996,908 | 23,573,156 | 20,750,730 | 22,673,022 |
| **Total Other Included Items** | 242,569,503 | 199,145,751 | 20,750,730 | 22,673,022 |
| ***Schedule 4: Average System Costs*** | | | | |
| **Total Operating Expenses** | 505,136,167 | 302,749,412 | 20,132,312 | 182,254,443 |
| *(Total O&M + Total Depreciation & Amortization + Total Taxes - Total Other Included Items)* | | | | |
| **Return from Rate Base** | 121,613,813 | 65,665,753 | 21,770,501 | 34,177,559 |
| *(Total Rate Base * Rate of Return)* | | | | |
| **Total Cost** | 626,749,980 | 368,415,165 | 41,902,813 | 216,432,002 |
| *(Total Operating Expenses + Return from Rate Base)* | | | | |

| | |
|---|---|
| Total Load (MWh) | 8,787,002 |
| 5% Distribution Losses (MWh) | 439,350 |
| **Average System Cost ($/MWh)** | **44.47** |

*(Total Production and Transmission Costs) / (Total Load + Distribution Losses)*

# Table 7.2
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| **Utility:** | IDAHO POWER |
| **Date Filed:** | 4/30/2003 |
| **Year/Quarter:** | **2002/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 1:*** *Plant Investment / Rate Base / Rate of Return* | | | | |
| Total Intanglibe Plant | 67,128,967 | 34,103,199 | 11,545,521 | 21,480,248 |
| Total Production Plant | 1,433,626,812 | 1,433,626,812 | 0 | 0 |
| Total Transmission Plant | 485,349,425 | 0 | 485,349,425 | 0 |
| Total Distribution Plant | 902,984,488 | 0 | 0 | 902,984,488 |
| Total General Plant | 198,329,401 | 73,175,605 | 44,187,178 | 80,966,618 |
| **Total Electric Plant In-Service** | 3,087,419,093 | 1,540,905,616 | 541,082,123 | 1,005,431,354 |
| **LESS:** | | | | |
| **Total Depreciation and Amortization** | 1,294,961,078 | 707,757,601 | 203,077,737 | 384,125,740 |
| **Total Net Plant** | 1,792,458,015 | 833,148,015 | 338,004,386 | 621,305,614 |
| *(Total Electric Plant In-Service) - (Total Depreciation & Amortization)* | | | | |
| **Assets and Other Debits (Comparative Balance Sheet)** | | | | |
| Cash Working Capital | 46,996,594 | 31,992,751 | 3,473,191 | 11,530,652 |
| Total Utility Plant | 94,362,283 | 731,829 | 401,610 | 93,228,843 |
| Total Other Property and Investments | 26,881 | 0 | 0 | 26,881 |
| Total Current and Accrued Assets | 61,219,932 | 34,517,003 | 9,335,111 | 17,367,818 |
| Total Deferred Debits | 650,062,474 | 237,551,964 | 18,699,819 | 393,810,690 |
| **Total Assets and Other Debits** | 852,668,164 | 304,793,548 | 31,909,732 | 515,964,884 |
| **LESS:** | | | | |
| **Liabilities and Other Credits (Comparative Balance Sheet)** | | | | |
| Total Other Noncurrent Liablities | 0 | 0 | 0 | 0 |
| Total Current and Accrued Liabilities | 91,235 | 91,235 | 0 | 0 |
| Total Deferred Credtis | 800,417,308 | 28,419,087 | 7,716,847 | 764,281,374 |
| **Total Liabilities and Other Credits** | 800,508,543 | 28,510,322 | 7,716,847 | 764,281,374 |
| **Total Rate Base** | 1,844,617,636 | 1,109,431,240 | 362,197,272 | 372,989,124 |
| *(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)* | | | | |

***Schedule 2: Weighted Average Cost of Long Term Debt***

| | |
|---|---|
| Long Term Debt | 953,229,728 |
| Interest for Year | 51,127,384 |
| **Rate of Return** | 5.36% |

*(Interest/Long Term Debt)*

# Table 7.2
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | IDAHO POWER |
| Date Filed: | 4/30/2003 |
| Year/Quarter: | **2002/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 3: Expenses*** | | | | |
| Total Production Expense | 475,199,888 | 475,199,888 | 0 | 0 |
| Total Transmission Expense | 15,459,670 | 0 | 15,459,670 | 0 |
| Total Distribution Expense | 41,943,849 | 0 | 0 | 41,943,849 |
| Total Customer and Sales Expenses | 25,011,421 | 0 | 0 | 25,011,421 |
| Total Administration and General Expenses | 63,330,753 | 25,714,948 | 12,325,860 | 25,289,945 |
| **Total Operations and Maintenance** | 620,945,581 | 500,914,836 | 27,785,530 | 92,245,215 |
| **Total Depreciation and Amortization** | 93,712,973 | 44,431,707 | 14,167,874 | 35,113,392 |
| ***Schedule 3A Items: Taxes*** | | | | |
| **Taxes Accrued, Prepaid, and Charged During Year** | | | | |
| Total Federal | (16,894,561) | 3,724,860 | 1,702,500 | (22,321,922) |
| Total State | 24,166,382 | 9,233,138 | 2,517,786 | 12,415,459 |
| Total County and Municipal | | | | |
| **Total Taxes** | 7,271,821 | 12,957,998 | 4,220,286 | (9,906,463) |
| ***Schedule 3B Items: Other Included Items*** | | | | |
| Total Disposition of Plant | 12,328 | 6,153 | 2,161 | 4,015 |
| Total Sales from Resale | 55,031,087 | 55,031,087 | 0 | 0 |
| Total Other Revenues | 39,981,570 | 508,484 | 23,288,535 | 16,184,551 |
| **Total Other Included Items** | 95,024,985 | 55,545,724 | 23,290,696 | 16,188,566 |
| ***Schedule 4: Average System Costs*** | | | | |
| **Total Operating Expenses** | 626,905,390 | 502,758,818 | 22,882,994 | 101,263,578 |
| *(Total O&M + Total Depreciation & Amortization + Total Taxes - Total Other Included Items)* | | | | |
| **Return from Rate Base** | 98,937,823 | 59,505,401 | 19,426,796 | 20,005,627 |
| *(Total Rate Base * Rate of Return)* | | | | |
| **Total Cost** | 725,843,213 | 562,264,219 | 42,309,790 | 121,269,205 |
| *(Total Operating Expenses + Return from Rate Base)* | | | | |

| | |
|---|---|
| Total Load (MWh) | 12,894,068 |
| 5% Distribution Losses (MWh) | 644,703 |
| **Average System Cost ($/MWh)** | **44.66** |

*(Total Production and Transmission Costs) / (Total Load + Distribution Losses)*

# Table 7.2
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | IDAHO POWER |
| Date Filed: | 4/30/2004 |
| Year/Quarter: | **2003/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 1:*** *Plant Investment / Rate Base / Rate of Return* | | | | |
| Total Intanglibe Plant | 71,794,683 | 35,617,292 | 12,880,486 | 23,296,905 |
| Total Production Plant | 1,456,953,896 | 1,456,953,896 | 0 | 0 |
| Total Transmission Plant | 526,886,598 | 0 | 526,886,598 | 0 |
| Total Distribution Plant | 952,978,561 | 0 | 0 | 952,978,561 |
| Total General Plant | 212,069,129 | 77,874,151 | 48,267,847 | 85,927,131 |
| **Total Electric Plant In-Service** | 3,220,682,867 | 1,570,445,340 | 588,034,930 | 1,062,202,597 |
| **LESS:** | | | | |
| **Total Depreciation and Amortization** | 1,239,604,536 | 616,549,083 | 210,519,937 | 412,535,516 |
| **Total Net Plant** | 1,981,078,331 | 953,896,257 | 377,514,993 | 649,667,081 |
| *(Total Electric Plant In-Service) - (Total Depreciation & Amortization)* | | | | |
| **Assets and Other Debits (Comparative Balance Sheet)** | | | | |
| Cash Working Capital | 36,198,855 | 20,140,483 | 4,061,606 | 11,996,766 |
| Total Utility Plant | 98,069,626 | 755,002 | 437,381 | 96,877,243 |
| Total Other Property and Investments | 14,225 | 0 | 0 | 14,225 |
| Total Current and Accrued Assets | 52,818,063 | 29,341,401 | 8,358,558 | 15,118,104 |
| Total Deferred Debits | 616,257,810 | 174,381,203 | 20,675,260 | 421,201,347 |
| **Total Assets and Other Debits** | 803,358,579 | 224,618,089 | 33,532,804 | 545,207,686 |
| **LESS:** | | | | |
| **Liabilities and Other Credits (Comparative Balance Sheet)** | | | | |
| Total Other Noncurrent Liablities | 0 | 0 | 0 | 0 |
| Total Current and Accrued Liabilities | 0 | 0 | 0 | 0 |
| Total Deferred Credtis | 1,867,932,822 | 101,228,014 | 34,306,972 | 1,732,397,837 |
| **Total Liabilities and Other Credits** | 1,867,932,822 | 101,228,014 | 34,306,972 | 1,732,397,837 |
| **Total Rate Base** | 916,504,088 | 1,077,286,332 | 376,740,826 | (537,523,071) |
| *(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)* | | | | |

***Schedule 2: Weighted Average Cost of Long Term Debt***

| | |
|---|---|
| Long Term Debt | 933,150,015 |
| Interest for Year | 54,645,483 |
| **Rate of Return** | 5.86% |

*(Interest/Long Term Debt)*

# Table 7.2
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | IDAHO POWER |
| Date Filed: | 4/30/2004 |
| Year/Quarter: | **2003/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 3: Expenses*** | | | | |
| Total Production Expense | 385,970,436 | 385,970,436 | 0 | 0 |
| Total Transmission Expense | 19,512,743 | 0 | 19,512,743 | 0 |
| Total Distribution Expense | 44,043,908 | 0 | 0 | 44,043,908 |
| Total Customer and Sales Expenses | 25,939,434 | 0 | 0 | 25,939,434 |
| Total Administration and General Expenses | 65,001,923 | 26,031,032 | 12,980,105 | 25,990,786 |
| **Total Operations and Maintenance** | 540,468,444 | 412,001,468 | 32,492,848 | 95,974,128 |
| **Total Depreciation and Amortization** | 97,760,033 | 45,575,475 | 15,091,615 | 37,092,942 |
| ***Schedule 3A Items: Taxes*** | | | | |
| **Taxes Accrued, Prepaid, and Charged During Year** | | | | |
| Total Federal | 99,392,740 | 3,633,002 | 1,692,396 | 94,067,342 |
| Total State | 26,616,074 | 9,234,093 | 2,721,506 | 14,660,475 |
| Total County and Municipal | | | | |
| **Total Taxes** | 126,008,814 | 12,867,095 | 4,413,902 | 108,727,817 |
| ***Schedule 3B Items: Other Included Items*** | | | | |
| Total Disposition of Plant | 20,012 | 9,758 | 3,654 | 6,600 |
| Total Sales from Resale | 71,572,857 | 71,572,857 | 0 | 0 |
| Total Other Revenues | 39,354,512 | 147,715 | 24,427,485 | 14,779,312 |
| **Total Other Included Items** | 110,947,381 | 71,730,330 | 24,431,138 | 14,785,912 |
| ***Schedule 4: Average System Costs*** | | | | |
| **Total Operating Expenses** | 653,289,910 | 398,713,708 | 27,567,227 | 227,008,976 |
| *(Total O&M + Total Depreciation & Amortization + Total Taxes - Total Other Included Items)* | | | | |
| **Return from Rate Base** | 53,670,694 | 63,086,139 | 22,062,031 | (31,477,477) |
| *(Total Rate Base * Rate of Return)* | | | | |
| **Total Cost** | 706,960,604 | 461,799,847 | 49,629,257 | 195,531,499 |
| *(Total Operating Expenses + Return from Rate Base)* | | | | |

| | |
|---|---|
| Total Load (MWh) | 12,980,031 |
| 5% Distribution Losses (MWh) | 649,002 |
| **Average System Cost ($/MWh)** | **37.52** |

*(Total Production and Transmission Costs) / (Total Load + Distribution Losses)*

# Table 7.2
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| **Utility:** | IDAHO POWER |
| **Date Filed:** | 4/18/2006 |
| **Year/Quarter:** | **2004/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 1:*** *Plant Investment / Rate Base / Rate of Return* | | | | |
| Total Intanglibe Plant | 76,754,564 | 37,491,726 | 14,169,638 | 25,093,200 |
| Total Production Plant | 1,482,517,098 | 1,482,517,098 | 0 | 0 |
| Total Transmission Plant | 560,303,124 | 0 | 560,303,124 | 0 |
| Total Distribution Plant | 992,248,198 | 0 | 0 | 992,248,198 |
| Total General Plant | 213,447,249 | 72,401,297 | 46,755,724 | 94,290,228 |
| **Total Electric Plant In-Service** | 3,325,270,233 | 1,592,410,121 | 621,228,486 | 1,111,631,626 |
| **LESS:** | | | | |
| **Total Depreciation and Amortization** | 1,316,124,554 | 657,454,906 | 223,066,040 | 435,603,607 |
| **Total Net Plant** | 2,009,145,679 | 934,955,215 | 398,162,446 | 676,028,018 |
| *(Total Electric Plant In-Service) - (Total Depreciation & Amortization)* | | | | |
| **Assets and Other Debits (Comparative Balance Sheet)** | | | | |
| Cash Working Capital | 35,353,677 | 16,872,929 | 4,514,997 | 13,965,750 |
| Total Utility Plant | 153,832,980 | 832,996 | 486,578 | 152,513,406 |
| Total Other Property and Investments | 32,458,340 | 0 | 0 | 32,458,340 |
| Total Current and Accrued Assets | 61,051,812 | 33,166,075 | 10,063,735 | 17,822,002 |
| Total Deferred Debits | 617,804,386 | 136,834,000 | 19,971,781 | 460,998,605 |
| **Total Assets and Other Debits** | 900,501,195 | 900,501,195 | 900,501,195 | 900,501,195 |
| **LESS:** | | | | |
| **Liabilities and Other Credits (Comparative Balance Sheet)** | | | | |
| Total Other Noncurrent Liablities | 0 | 0 | 0 | 0 |
| Total Current and Accrued Liabilities | 445 | 445 | 0 | 0 |
| Total Deferred Credtis | 961,026,762 | 113,036,668 | 35,214,359 | 812,775,735 |
| **Total Liabilities and Other Credits** | 961,027,207 | 113,037,113 | 35,214,359 | 812,775,735 |
| **Total Rate Base** | 1,948,619,667 | 1,009,624,103 | 397,985,178 | 541,010,386 |
| *(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)* | | | | |

***Schedule 2: Weighted Average Cost of Long Term Debt***

| | |
|---|---|
| Long Term Debt | 987,045,000 |
| Interest for Year | 50,317,585 |
| **Rate of Return** | 5.10% |

*(Interest/Long Term Debt)*

# Table 7.2
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | IDAHO POWER |
| Date Filed: | 4/18/2006 |
| Year/Quarter: | 2004/Q4 |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 3: Expenses*** | | | | |
| Total Production Expense | 407,579,274 | 407,579,274 | 0 | 0 |
| Total Transmission Expense | 23,835,089 | 0 | 23,835,089 | 0 |
| Total Distribution Expense | 39,349,285 | 0 | 0 | 39,349,285 |
| Total Customer and Sales Expenses | 25,843,019 | 0 | 0 | 25,843,019 |
| Total Administration and General Expenses | 85,126,373 | 26,307,787 | 12,284,890 | 46,533,695 |
| **Total Operations and Maintenance** | 581,733,040 | 433,887,061 | 36,119,979 | 111,725,999 |
| **Total Depreciation and Amortization** | 101,037,621 | 47,308,408 | 17,521,822 | 36,207,392 |
| ***Schedule 3A Items: Taxes*** | | | | |
| **Taxes Accrued, Prepaid, and Charged During Year** | | | | |
| Total Federal | 41,150,426 | 2,818,967 | 1,267,183 | 37,064,275 |
| Total State | 22,970,647 | 8,824,407 | 2,700,405 | 11,445,836 |
| Total County and Municipal | | | | |
| **Total Taxes** | 64,121,073 | 11,643,374 | 3,967,588 | 48,510,111 |
| ***Schedule 3B Items: Other Included Items*** | | | | |
| Total Disposition of Plant | (2,071) | (992) | (387) | (692) |
| Total Sales from Resale | 121,147,646 | 121,147,646 | 0 | 0 |
| Total Other Revenues | 42,724,578 | 2,018,555 | 23,523,292 | 17,182,731 |
| **Total Other Included Items** | 163,870,153 | 123,165,209 | 23,522,905 | 17,182,039 |
| ***Schedule 4: Average System Costs*** | | | | |
| **Total Operating Expenses** | 583,021,581 | 369,673,634 | 34,086,484 | 179,261,463 |
| *(Total O&M + Total Depreciation & Amortization + Total Taxes - Total Other Included Items)* | | | | |
| **Return from Rate Base** | 99,336,743 | 51,468,623 | 20,288,490 | 27,579,630 |
| *(Total Rate Base * Rate of Return)* | | | | |
| **Total Cost** | 682,358,324 | 421,142,257 | 54,374,975 | 206,841,093 |
| *(Total Operating Expenses + Return from Rate Base)* | | | | |

| | |
|---|---|
| Total Load (MWh) | 13,239,589 |
| 5% Distribution Losses (MWh) | 661,979 |
| **Average System Cost ($/MWh)** | **34.21** |

*(Total Production and Transmission Costs) / (Total Load + Distribution Losses)*

# Table 7.2
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | IDAHO POWER |
| Date Filed: | 4/18/2006 |
| Year/Quarter: | **2005/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 1:*** *Plant Investment / Rate Base / Rate of Return* | | | | |
| Total Intanglibe Plant | 69,742,756 | 34,169,047 | 12,687,771 | 22,885,939 |
| Total Production Plant | 1,563,008,126 | 1,563,008,126 | 0 | 0 |
| Total Transmission Plant | 580,381,676 | 0 | 580,381,676 | 0 |
| Total Distribution Plant | 1,046,880,491 | 0 | 0 | 1,046,880,491 |
| Total General Plant | 217,508,189 | 78,295,357 | 49,809,896 | 89,402,937 |
| **Total Electric Plant In-Service** | 3,477,521,238 | 1,675,472,529 | 642,879,342 | 1,159,169,367 |
| **LESS:** | | | | |
| **Total Depreciation and Amortization** | 1,364,640,116 | 690,005,169 | 226,645,040 | 447,989,907 |
| **Total Net Plant** | 2,112,881,122 | 985,467,361 | 416,234,302 | 711,179,459 |
| *(Total Electric Plant In-Service) - (Total Depreciation & Amortization)* | | | | |
| **Assets and Other Debits (Comparative Balance Sheet)** | | | | |
| Cash Working Capital | 29,917,143 | 13,386,874 | 4,659,211 | 11,871,058 |
| Total Utility Plant | 152,266,070 | 969,388 | 528,704 | 150,767,978 |
| Total Other Property and Investments | 1,025,159 | 0 | 0 | 1,025,159 |
| Total Current and Accrued Assets | 59,722,279 | 35,247,240 | 8,729,303 | 15,745,736 |
| Total Deferred Debits | 629,637,669 | 123,945,998 | 22,167,559 | 483,524,112 |
| **Total Assets and Other Debits** | 872,568,320 | 173,549,500 | 36,084,777 | 662,934,044 |
| **LESS:** | | | | |
| **Liabilities and Other Credits (Comparative Balance Sheet)** | | | | |
| Total Other Noncurrent Liablities | 0 | 0 | 0 | 0 |
| Total Current and Accrued Liabilities | 0 | 0 | 0 | 0 |
| Total Deferred Credtis | 1,042,495,122 | 180,434,287 | 45,427,024 | 816,633,811 |
| **Total Liabilities and Other Credits** | 1,042,495,122 | 180,434,287 | 45,427,024 | 816,633,811 |
| **Total Rate Base** | 1,942,954,320 | 978,582,574 | 406,892,055 | 557,479,691 |
| *(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)* | | | | |

***Schedule 2: Weighted Average Cost of Long Term Debt***

| | |
|---|---|
| Long Term Debt | 987,045,000 |
| Interest for Year | 53,339,531 |
| **Rate of Return** | 5.40% |
| *(Interest/Long Term Debt)* | |

# Table 7.2
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | IDAHO POWER |
| Date Filed: | 4/18/2006 |
| Year/Quarter: | **2005/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 3: Expenses*** | | | | |
| Total Production Expense | 397,057,412 | 397,057,412 | 0 | 0 |
| Total Transmission Expense | 21,989,736 | 0 | 21,989,736 | 0 |
| Total Distribution Expense | 38,324,600 | 0 | 0 | 38,324,600 |
| Total Customer and Sales Expenses | 25,714,779 | 0 | 0 | 25,714,779 |
| Total Administration and General Expenses | 81,724,444 | 35,511,407 | 15,283,951 | 30,929,086 |
| **Total Operations and Maintenance** | 564,810,971 | 432,568,819 | 37,273,687 | 94,968,465 |
| **Total Depreciation and Amortization** | 101,507,467 | 48,014,326 | 17,647,331 | 35,845,811 |
| ***Schedule 3A Items: Taxes*** | | | | |
| **Taxes Accrued, Prepaid, and Charged During Year** | | | | |
| Total Federal | 50,071,224 | 4,349,191 | 1,841,872 | 43,880,160 |
| Total State | 23,629,680 | 9,168,398 | 2,720,003 | 11,741,279 |
| Total County and Municipal | | | | |
| **Total Taxes** | 73,700,904 | 13,517,590 | 4,561,875 | 55,621,439 |
| ***Schedule 3B Items: Other Included Items*** | | | | |
| Total Disposition of Plant | 591 | 285 | 109 | 197 |
| Total Sales from Resale | 142,794,426 | 142,794,426 | 0 | 0 |
| Total Other Revenues | 38,611,625 | 199,361 | 21,275,041 | 17,137,223 |
| **Total Other Included Items** | 181,406,642 | 142,994,072 | 21,275,150 | 17,137,420 |
| ***Schedule 4: Average System Costs*** | | | | |
| **Total Operating Expenses** | 558,612,700 | 351,106,662 | 38,207,743 | 169,298,295 |
| *(Total O&M + Total Depreciation & Amortization + Total Taxes - Total Other Included Items)* | | | | |
| **Return from Rate Base** | 104,996,502 | 52,882,225 | 21,988,290 | 30,125,987 |
| *(Total Rate Base * Rate of Return)* | | | | |
| **Total Cost** | 663,609,202 | 403,988,887 | 60,196,033 | 199,424,282 |
| *(Total Operating Expenses + Return from Rate Base)* | | | | |

| | |
|---|---|
| Total Load (MWh) | 13,288,812 |
| 5% Distribution Losses (MWh) | 664,441 |
| **Average System Cost ($/MWh)** | **33.27** |

*(Total Production and Transmission Costs) / (Total Load + Distribution Losses)*

# Table 7.2
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | IDAHO POWER |
| Date Filed: | 4/18/2007 |
| Year/Quarter: | 2006/Q4 |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 1:*** *Plant Investment / Rate Base / Rate of Return* | | | | |
| Total Intanglibe Plant | 72,094,030 | 34,827,487 | 13,271,332 | 23,995,211 |
| Total Production Plant | 1,592,790,118 | 1,592,790,118 | 0 | 0 |
| Total Transmission Plant | 606,947,191 | 0 | 606,947,191 | 0 |
| Total Distribution Plant | 1,097,389,958 | 0 | 0 | 1,097,389,958 |
| Total General Plant | 214,927,062 | 74,534,385 | 50,471,800 | 89,920,876 |
| **Total Electric Plant In-Service** | 3,584,148,359 | 1,702,151,991 | 670,690,323 | 1,211,306,046 |
| **LESS:** | | | | |
| **Total Depreciation and Amortization** | 1,406,209,952 | 710,134,157 | 236,761,039 | 459,314,756 |
| **Total Net Plant** | 2,177,938,407 | 992,017,834 | 433,929,284 | 751,991,290 |
| *(Total Electric Plant In-Service) - (Total Depreciation & Amortization)* | | | | |
| **Assets and Other Debits (Comparative Balance Sheet)** | | | | |
| Cash Working Capital | 29,153,644 | 11,278,671 | 5,218,293 | 12,656,680 |
| Total Utility Plant | 212,449,340 | 902,907 | 517,233 | 211,029,201 |
| Total Other Property and Investments | 3,696 | 0 | 0 | 3,696 |
| Total Current and Accrued Assets | 63,204,062 | 38,376,477 | 8,841,580 | 15,986,005 |
| Total Deferred Debits | 645,699,285 | 109,499,915 | 31,905,429 | 504,293,941 |
| **Total Assets and Other Debits** | 950,510,027 | 160,057,970 | 46,482,534 | 743,969,523 |
| **LESS:** | | | | |
| **Liabilities and Other Credits (Comparative Balance Sheet)** | | | | |
| Total Other Noncurrent Liablities | 0 | 0 | 0 | 0 |
| Total Current and Accrued Liabilities | 1,462,637 | 1,462,637 | 0 | 0 |
| Total Deferred Credtis | 953,195,185 | 106,425,268 | 32,400,117 | 814,369,800 |
| **Total Liabilities and Other Credits** | 954,657,822 | 107,887,905 | 32,400,117 | 814,369,800 |
| **Total Rate Base** | 2,173,790,612 | 1,044,187,898 | 448,011,701 | 681,591,013 |
| *(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)* | | | | |

***Schedule 2: Weighted Average Cost of Long Term Debt***

| | |
|---|---|
| Long Term Debt | 987,045,000 |
| Interest for Year | 53,744,453 |
| **Rate of Return** | 5.44% |

*(Interest/Long Term Debt)*

## Table 7.2
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| **Utility:** | IDAHO POWER |
| **Date Filed:** | 4/18/2007 |
| **Year/Quarter:** | **2006/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 3: Expenses*** | | | | |
| Total Production Expense | 450,334,589 | 450,263,162 | 0 | 71,427 |
| Total Transmission Expense | 23,669,858 | 0 | 23,669,858 | 0 |
| Total Distribution Expense | 41,984,481 | 0 | 0 | 41,984,481 |
| Total Customer and Sales Expenses | 28,971,362 | 0 | 0 | 28,971,362 |
| Total Administration and General Expenses | 86,726,893 | 38,424,236 | 18,076,487 | 30,226,170 |
| **Total Operations and Maintenance** | 631,687,183 | 488,687,398 | 41,746,345 | 101,253,440 |
| **Total Depreciation and Amortization** | 99,893,071 | 47,413,976 | 17,164,994 | 35,314,101 |
| ***Schedule 3A Items: Taxes*** | | | | |
| **Taxes Accrued, Prepaid, and Charged During Year** | | | | |
| Total Federal | 84,018,621 | 4,528,019 | 2,069,554 | 77,421,048 |
| Total State | 29,462,670 | 8,604,662 | 2,627,440 | 18,230,568 |
| Total County and Municipal | | | | |
| **Total Taxes** | 113,481,291 | 13,132,680 | 4,696,994 | 95,651,617 |
| ***Schedule 3B Items: Other Included Items*** | | | | |
| Total Disposition of Plant | (46,144) | (21,914) | (8,635) | (15,595) |
| Total Sales from Resale | 260,717,491 | 260,717,491 | 0 | 0 |
| Total Other Revenues | 34,737,531 | 141,344 | 18,216,051 | 16,380,135 |
| **Total Other Included Items** | 295,408,878 | 260,836,921 | 18,207,416 | 16,364,540 |
| ***Schedule 4: Average System Costs*** | | | | |
| **Total Operating Expenses** *(Total O&M + Total Depreciation & Amortization + Total Taxes - Total Other Included Items)* | 549,652,667 | 288,397,133 | 45,400,916 | 215,854,617 |
| **Return from Rate Base** *(Total Rate Base * Rate of Return)* | 118,362,575 | 56,855,875 | 24,394,170 | 37,112,529 |
| **Total Cost** *(Total Operating Expenses + Return from Rate Base)* | 668,015,242 | 345,253,009 | 69,795,087 | 252,967,146 |

| | |
|---|---|
| Total Load (MWh) | 13,939,314 |
| 5% Distribution Losses (MWh) | 696,966 |
| **Average System Cost ($/MWh)** | **28.36** |

*(Total Production and Transmission Costs) / (Total Load + Distribution Losses)*

# Table 7.6
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| **Utility:** | Puget (PSE) |
| **Date Filed:** | 4/30/2003 |
| **Year/Quarter:** | **2002/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 1:*** *Plant Investment / Rate Base / Rate of Return* | | | | |
| Total Intanglibe Plant | 20,548,638 | 5,885,668 | 1,452,323 | 13,210,647 |
| Total Production Plant | 1,113,740,453 | 1,113,740,453 | 0 | 0 |
| Total Transmission Plant | 274,822,052 | 0 | 274,822,052 | 0 |
| Total Distribution Plant | 2,499,840,829 | 0 | 0 | 2,499,840,829 |
| Total General Plant | 154,610,099 | 37,879,739 | 9,940,248 | 106,790,112 |
| **Total Electric Plant In-Service** | 4,063,562,071 | 1,157,505,860 | 286,214,623 | 2,619,841,588 |
| **LESS:** | | | | |
| **Total Depreciation and Amortization** | 1,840,732,065 | 650,909,719 | 112,800,046 | 1,077,022,300 |
| **Total Net Plant** | 2,222,830,006 | 506,596,140 | 173,414,577 | 1,542,819,288 |
| *(Total Electric Plant In-Service) - (Total Depreciation & Amortization)* | | | | |
| **Assets and Other Debits (Comparative Balance Sheet)** | | | | |
| Cash Working Capital | 53,563,866 | 28,048,872 | 5,523,039 | 19,991,955 |
| Total Utility Plant | 647,245,440 | 217,778,197 | 34,522,898 | 394,944,346 |
| Total Other Property and Investments | 41,526,680 | 0 | 0 | 41,526,680 |
| Total Current and Accrued Assets | 61,064,660 | 35,751,634 | 2,507,179 | 22,805,846 |
| Total Deferred Debits | 763,270,926 | 268,991,883 | 9,151,842 | 485,127,201 |
| **Total Assets and Other Debits** | 1,566,671,572 | 550,570,585 | 51,704,958 | 964,396,028 |
| **LESS:** | | | | |
| **Liabilities and Other Credits (Comparative Balance Sheet)** | | | | |
| Total Other Noncurrent Liablities | 0 | 0 | 0 | 0 |
| Total Current and Accrued Liabilities | 2,410,030 | 2,410,030 | 0 | 0 |
| Total Deferred Credtis | 1,043,066,464 | 59,825,139 | 5,661,048 | 977,580,278 |
| **Total Liabilities and Other Credits** | 1,045,476,494 | 62,235,169 | 5,661,048 | 977,580,278 |
| **Total Rate Base** | 2,744,025,084 | 994,931,557 | 219,458,488 | 1,529,635,039 |
| *(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)* | | | | |

***Schedule 2: Weighted Average Cost of Long Term Debt***

| | |
|---|---|
| Long Term Debt | 2,093,860,000 |
| Interest for Year | 182,204,172 |
| **Rate of Return** | 8.70% |
| *(Interest/Long Term Debt)* | |

# Table 7.6
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| **Utility:** | Puget (PSE) |
| **Date Filed:** | 4/30/2003 |
| **Year/Quarter:** | **2002/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 3: Expenses*** | | | | |
| Total Production Expense | 836,177,740 | 836,177,740 | 0 | 0 |
| Total Transmission Expense | 41,545,182 | 0 | 41,545,182 | 0 |
| Total Distribution Expense | 59,968,030 | 0 | 0 | 59,968,030 |
| Total Customer and Sales Expenses | 60,008,880 | 0 | 0 | 60,008,880 |
| Total Administration and General Expenses | 54,657,778 | 12,059,916 | 2,639,129 | 39,958,733 |
| **Total Operations and Maintenance** | 1,052,357,610 | 848,237,656 | 44,184,311 | 159,935,643 |
| **Total Depreciation and Amortization** | 141,257,098 | 42,663,445 | 9,119,231 | 89,474,422 |
| ***Schedule 3A Items: Taxes*** | | | | |
| **Taxes Accrued, Prepaid, and Charged During Year** | | | | |
| Total Federal | (82,580,914) | 2,673,184 | 543,922 | (85,798,020) |
| Total State | 193,737,869 | 18,409,649 | 2,316,720 | 173,011,500 |
| Total County and Municipal | 0 | 0 | 0 | 0 |
| **Total Taxes** | 111,156,955 | 21,082,833 | 2,860,642 | 87,213,480 |
| ***Schedule 3B Items: Other Included Items*** | | | | |
| Total Disposition of Plant | 206,177 | 58,730 | 14,522 | 132,926 |
| Total Sales from Resale | 88,682,767 | 88,682,767 | 0 | 0 |
| Total Other Revenues | 16,373,824 | (8,319,276) | 22,043,806 | 2,649,294 |
| **Total Other Included Items** | 105,262,768 | 80,422,221 | 22,058,328 | 2,782,219 |
| ***Schedule 4: Average System Costs*** | | | | |
| **Total Operating Expenses** | 1,199,508,895 | 831,561,713 | 34,105,857 | 333,841,326 |
| *(Total O&M + Total Depreciation & Amortization + Total Taxes - Total Other Included Items)* | | | | |
| **Return from Rate Base** | 238,780,443 | 86,577,269 | 19,096,908 | 133,106,266 |
| *(Total Rate Base * Rate of Return)* | | | | |
| **Total Cost** | 1,438,289,338 | 918,138,982 | 53,202,765 | 466,947,591 |
| *(Total Operating Expenses + Return from Rate Base)* | | | | |

| | |
|---|---|
| Total Load (MWh) | 19,253,824 |
| 5% Distribution Losses (MWh) | 962,691 |
| **Average System Cost ($/MWh)** | **48.05** |

*(Total Production and Transmission Costs) / (Total Load + Distribution Losses)*

# Table 7.6
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | Puget (PSE) |
| Date Filed: | 4/30/2004 |
| Year/Quarter: | 2003/Q4 |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 1:*** *Plant Investment / Rate Base / Rate of Return* | | | | |
| Total Intanglibe Plant | 19,184,270 | 5,506,954 | 1,336,483 | 12,340,833 |
| Total Production Plant | 1,131,938,765 | 1,131,938,765 | 0 | 0 |
| Total Transmission Plant | 274,710,175 | 0 | 274,710,175 | 0 |
| Total Distribution Plant | 2,536,623,123 | 0 | 0 | 2,536,623,123 |
| Total General Plant | 137,448,837 | 35,622,513 | 8,642,675 | 93,183,650 |
| **Total Electric Plant In-Service** | 4,099,905,170 | 1,173,068,232 | 284,689,332 | 2,642,147,606 |
| **LESS:** | | | | |
| **Total Depreciation and Amortization** | 1,915,493,306 | 694,753,456 | 118,048,872 | 1,102,690,978 |
| **Total Net Plant** | 2,184,411,864 | 478,314,776 | 166,640,460 | 1,539,456,628 |
| *(Total Electric Plant In-Service) - (Total Depreciation & Amortization)* | | | | |
| **Assets and Other Debits (Comparative Balance Sheet)** | | | | |
| Cash Working Capital | 57,358,978 | 29,937,126 | 5,809,698 | 21,612,154 |
| Total Utility Plant | 682,178,288 | 228,219,892 | 36,488,136 | 417,470,260 |
| Total Other Property and Investments | 44,942,191 | 0 | 0 | 44,942,191 |
| Total Current and Accrued Assets | 62,551,079 | 38,172,343 | 2,382,175 | 21,996,561 |
| Total Deferred Debits | 838,126,507 | 334,444,116 | 11,189,225 | 492,493,166 |
| **Total Assets and Other Debits** | 1,685,157,043 | 630,773,477 | 55,869,234 | 998,514,332 |
| **LESS:** | | | | |
| **Liabilities and Other Credits (Comparative Balance Sheet)** | | | | |
| Total Other Noncurrent Liablities | 0 | 0 | 0 | 0 |
| Total Current and Accrued Liabilities | 3,635,722 | 3,635,722 | 0 | 0 |
| Total Deferred Credtis | 1,018,122,910 | 36,649,840 | 5,685,253 | 975,787,817 |
| **Total Liabilities and Other Credits** | 1,021,758,632 | 40,285,562 | 5,685,253 | 975,787,817 |
| **Total Rate Base** | 2,847,810,275 | 1,068,802,691 | 216,824,441 | 1,562,183,143 |
| *(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)* | | | | |

***Schedule 2: Weighted Average Cost of Long Term Debt***

| | |
|---|---|
| Long Term Debt | 2,335,157,709 |
| Interest for Year | 170,690,378 |
| **Rate of Return** | 7.31% |
| *(Interest/Long Term Debt)* | |

## Table 7.6
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | Puget (PSE) |
| Date Filed: | 4/30/2004 |
| Year/Quarter: | **2003/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 3: Expenses*** | | | | |
| Total Production Expense | 896,684,728 | 896,684,728 | 0 | 0 |
| Total Transmission Expense | 43,495,781 | 0 | 43,495,781 | 0 |
| Total Distribution Expense | 57,740,065 | 0 | 0 | 57,740,065 |
| Total Customer and Sales Expenses | 71,401,564 | 0 | 0 | 71,401,564 |
| Total Administration and General Expenses | 61,067,257 | 14,329,848 | 2,981,805 | 43,755,604 |
| **Total Operations and Maintenance** | 1,130,389,395 | 911,014,576 | 46,477,586 | 172,897,233 |
| **Total Depreciation and Amortization** | 144,031,071 | 45,199,107 | 8,819,904 | 90,012,060 |
| ***Schedule 3A Items: Taxes*** | | | | |
| **Taxes Accrued, Prepaid, and Charged During Year** | | | | |
| Total Federal | 25,653,888 | 2,899,665 | 545,796 | 22,208,428 |
| Total State | 191,500,792 | 24,267,242 | 2,339,709 | 164,893,841 |
| Total County and Municipal | 0 | 0 | 0 | 0 |
| **Total Taxes** | 217,154,680 | 27,166,907 | 2,885,504 | 187,102,269 |
| ***Schedule 3B Items: Other Included Items*** | | | | |
| Total Disposition of Plant | (4,734,298) | (1,354,581) | (328,740) | (3,050,976) |
| Total Sales from Resale | 191,876,710 | 191,876,710 | 0 | 0 |
| Total Other Revenues | 35,946,385 | 2,053,463 | 9,098,184 | 24,794,738 |
| **Total Other Included Items** | 223,088,797 | 192,575,592 | 8,769,444 | 21,743,761 |
| ***Schedule 4: Average System Costs*** | | | | |
| **Total Operating Expenses** | 1,268,486,349 | 790,804,998 | 49,413,550 | 428,267,801 |
| *(Total O&M + Total Depreciation & Amortization + Total Taxes - Total Other Included Items)* | | | | |
| **Return from Rate Base** | 208,163,162 | 78,125,060 | 15,848,971 | 114,189,132 |
| *(Total Rate Base * Rate of Return)* | | | | |
| **Total Cost** | 1,476,649,511 | 868,930,058 | 65,262,520 | 542,456,933 |
| *(Total Operating Expenses + Return from Rate Base)* | | | | |

| | |
|---|---|
| Total Load (MWh) | 19,591,637 |
| 5% Distribution Losses (MWh) | 979,582 |
| **Average System Cost ($/MWh)** | **45.41** |

*(Total Production and Transmission Costs) / (Total Load + Distribution Losses)*

## Table 7.6
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| **Utility:** | Puget (PSE) |
| **Date Filed:** | 4/25/2005 |
| **Year/Quarter:** | **2004/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 1:*** *Plant Investment / Rate Base / Rate of Return* | | | | |
| Total Intanglibe Plant | 28,335,684 | 7,994,030 | 2,016,408 | 18,325,246 |
| Total Production Plant | 1,143,775,811 | 1,143,775,811 | 0 | 0 |
| Total Transmission Plant | 288,505,193 | 0 | 288,505,193 | 0 |
| Total Distribution Plant | 2,621,953,457 | 0 | 0 | 2,621,953,457 |
| Total General Plant | 135,019,392 | 34,233,870 | 8,508,741 | 92,276,781 |
| **Total Electric Plant In-Service** | 4,217,589,537 | 1,186,003,710 | 299,030,342 | 2,732,555,485 |
| **LESS:** | | | | |
| **Total Depreciation and Amortization** | 2,006,378,009 | 715,882,011 | 127,761,147 | 1,162,734,851 |
| **Total Net Plant** | 2,211,211,528 | 470,121,699 | 171,269,196 | 1,569,820,633 |
| *(Total Electric Plant In-Service) - (Total Depreciation & Amortization)* | | | | |
| **Assets and Other Debits (Comparative Balance Sheet)** | | | | |
| Cash Working Capital | 57,357,955 | 31,122,459 | 5,921,318 | 20,314,178 |
| Total Utility Plant | 728,052,157 | 236,666,385 | 40,054,402 | 451,331,370 |
| Total Other Property and Investments | 62,016,981 | 13,765,107 | 0 | 48,251,874 |
| Total Current and Accrued Assets | 55,511,431 | 29,114,342 | 2,616,666 | 23,780,423 |
| Total Deferred Debits | 848,132,126 | 392,538,494 | 11,133,586 | 444,460,047 |
| **Total Assets and Other Debits** | 1,751,070,650 | 703,206,787 | 59,725,971 | 988,137,892 |
| **LESS:** | | | | |
| **Liabilities and Other Credits (Comparative Balance Sheet)** | | | | |
| Total Other Noncurrent Liablities | 249,455 | 249,455 | 0 | 0 |
| Total Current and Accrued Liabilities | 19,260,915 | 19,260,915 | 0 | 0 |
| Total Deferred Credtis | 1,062,210,581 | 38,563,659 | 5,275,158 | 1,018,371,764 |
| **Total Liabilities and Other Credits** | 1,081,720,951 | 58,074,029 | 5,275,158 | 1,018,371,764 |
| **Total Rate Base** | 2,880,561,227 | 1,115,254,457 | 225,720,009 | 1,539,586,761 |
| *(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)* | | | | |

### ***Schedule 2: Weighted Average Cost of Long Term Debt***

| | |
|---|---|
| Long Term Debt | 2,377,499,400 |
| Interest for Year | 161,737,171 |
| **Rate of Return** | 6.80% |

*(Interest/Long Term Debt)*

# Table 7.6
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | Puget (PSE) |
| Date Filed: | 4/25/2005 |
| Year/Quarter: | **2004/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 3: Expenses*** | | | | |
| Total Production Expense | 867,778,875 | 867,778,875 | 0 | 0 |
| Total Transmission Expense | 44,632,927 | 0 | 44,632,927 | 0 |
| Total Distribution Expense | 61,075,209 | 0 | 0 | 61,075,209 |
| Total Customer and Sales Expenses | 57,029,385 | 0 | 0 | 57,029,385 |
| Total Administration and General Expenses | 60,537,482 | 13,391,035 | 2,737,614 | 44,408,833 |
| **Total Operations and Maintenance** | 1,091,053,878 | 881,169,910 | 47,370,541 | 162,513,427 |
| **Total Depreciation and Amortization** | 147,343,645 | 45,667,518 | 9,102,078 | 92,574,049 |
| ***Schedule 3A Items: Taxes*** | | | | |
| **Taxes Accrued, Prepaid, and Charged During Year** | | | | |
| Total Federal | 9,796,715 | 2,770,899 | 504,592 | 6,521,224 |
| Total State | 202,120,572 | 19,547,932 | 2,459,701 | 180,112,939 |
| Total County and Municipal | 0 | 0 | 0 | 0 |
| **Total Taxes** | 211,917,287 | 22,318,831 | 2,964,293 | 186,634,163 |
| ***Schedule 3B Items: Other Included Items*** | | | | |
| Total Disposition of Plant | (4,734,298) | (1,331,304) | (335,665) | (3,067,328) |
| Total Sales from Resale | 115,356,097 | 115,356,097 | 0 | 0 |
| Total Other Revenues | 47,584,376 | 3,619,535 | 12,057,799 | 31,907,042 |
| **Total Other Included Items** | 158,206,175 | 117,644,328 | 11,722,133 | 28,839,714 |
| ***Schedule 4: Average System Costs*** | | | | |
| **Total Operating Expenses** | 1,292,108,635 | 831,511,931 | 47,714,779 | 412,881,925 |
| *(Total O&M + Total Depreciation & Amortization + Total Taxes - Total Other Included Items)* | | | | |
| **Return from Rate Base** | 195,959,597 | 75,868,831 | 15,355,342 | 104,735,424 |
| *(Total Rate Base * Rate of Return)* | | | | |
| **Total Cost** | 1,488,068,232 | 907,380,762 | 63,070,120 | 517,617,349 |
| *(Total Operating Expenses + Return from Rate Base)* | | | | |

| | |
|---|---|
| Total Load (MWh) | 19,876,790 |
| 5% Distribution Losses (MWh) | 993,840 |
| **Average System Cost ($/MWh)** | **46.50** |

*(Total Production and Transmission Costs) / (Total Load + Distribution Losses)*

## Table 7.6
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| **Utility:** | Puget (PSE) |
| **Date Filed:** | 4/18/2006 |
| **Year/Quarter:** | **2005/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 1:*** *Plant Investment / Rate Base / Rate of Return* | | | | |
| Total Intanglibe Plant | 30,282,492 | 9,132,015 | 2,040,437 | 19,110,040 |
| Total Production Plant | 1,319,444,433 | 1,319,444,433 | 0 | 0 |
| Total Transmission Plant | 294,813,676 | 0 | 294,813,676 | 0 |
| Total Distribution Plant | 2,761,125,181 | 0 | 0 | 2,761,125,181 |
| Total General Plant | 136,430,064 | 38,040,948 | 8,308,853 | 90,080,263 |
| **Total Electric Plant In-Service** | 4,542,095,846 | 1,366,617,396 | 305,162,965 | 2,870,315,484 |
| **LESS:** | | | | |
| **Total Depreciation and Amortization** | 2,105,742,831 | 762,788,528 | 133,207,295 | 1,209,747,009 |
| **Total Net Plant** | 2,436,353,015 | 603,828,869 | 171,955,671 | 1,660,568,475 |
| *(Total Electric Plant In-Service) - (Total Depreciation & Amortization)* | | | | |
| **Assets and Other Debits (Comparative Balance Sheet)** | | | | |
| Cash Working Capital | 58,101,129 | 29,752,748 | 6,869,835 | 21,478,545 |
| Total Utility Plant | 867,504,480 | 263,750,542 | 41,532,476 | 562,221,462 |
| Total Other Property and Investments | 80,807,501 | 28,464,159 | 0 | 52,343,342 |
| Total Current and Accrued Assets | 129,090,210 | 97,000,997 | 3,095,723 | 28,993,490 |
| Total Deferred Debits | 936,128,076 | 422,953,494 | 21,366,252 | 491,808,330 |
| **Total Assets and Other Debits** | 2,071,631,396 | 841,921,941 | 72,864,285 | 1,156,845,170 |
| **LESS:** | | | | |
| **Liabilities and Other Credits (Comparative Balance Sheet)** | | | | |
| Total Other Noncurrent Liablities | 0 | 0 | 0 | 0 |
| Total Current and Accrued Liabilities | 9,771,867 | 9,771,867 | 0 | 0 |
| Total Deferred Credtis | 1,181,457,175 | 59,353,069 | 6,631,045 | 1,115,473,061 |
| **Total Liabilities and Other Credits** | 1,191,229,042 | 69,124,936 | 6,631,045 | 1,115,473,061 |
| **Total Rate Base** | 3,316,755,369 | 1,376,625,874 | 238,188,911 | 1,701,940,584 |
| *(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)* | | | | |

### ***Schedule 2: Weighted Average Cost of Long Term Debt***

| | |
|---|---|
| Long Term Debt | 2,503,999,400 |
| Interest for Year | 162,147,926 |
| **Rate of Return** | 6.48% |

*(Interest/Long Term Debt)*

# Table 7.6
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | Puget (PSE) |
| Date Filed: | 4/18/2006 |
| Year/Quarter: | **2005/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 3: Expenses*** | | | | |
| Total Production Expense | 1,012,054,130 | 1,012,054,130 | 0 | 0 |
| Total Transmission Expense | 52,111,661 | 0 | 52,111,661 | 0 |
| Total Distribution Expense | 61,087,500 | 0 | 0 | 61,087,500 |
| Total Customer and Sales Expenses | 62,543,873 | 0 | 0 | 62,543,873 |
| Total Administration and General Expenses | 67,441,589 | 16,397,580 | 2,847,019 | 48,196,990 |
| **Total Operations and Maintenance** | 1,255,238,753 | 1,028,451,710 | 54,958,680 | 171,828,363 |
| **Total Depreciation and Amortization** | 152,347,107 | 48,334,893 | 9,218,561 | 94,793,653 |
| ***Schedule 3A Items: Taxes*** | | | | |
| **Taxes Accrued, Prepaid, and Charged During Year** | | | | |
| Total Federal | 138,720,821 | 3,447,190 | 536,908 | 134,736,723 |
| Total State | 220,509,586 | 20,747,744 | 2,449,256 | 197,312,586 |
| Total County and Municipal | 0 | 0 | 0 | 0 |
| **Total Taxes** | 359,230,407 | 24,194,934 | 2,986,164 | 332,049,309 |
| ***Schedule 3B Items: Other Included Items*** | | | | |
| Total Disposition of Plant | (992,876) | (298,735) | (66,707) | (627,434) |
| Total Sales from Resale | 177,304,684 | 177,304,684 | 0 | 0 |
| Total Other Revenues | 64,487,306 | 11,333,810 | 5,394,178 | 47,759,318 |
| **Total Other Included Items** | 240,799,114 | 188,339,759 | 5,327,471 | 47,131,884 |
| ***Schedule 4: Average System Costs*** | | | | |
| **Total Operating Expenses** | 1,526,017,153 | 912,641,778 | 61,835,934 | 551,539,441 |
| *(Total O&M + Total Depreciation & Amortization + Total Taxes - Total Other Included Items)* | | | | |
| **Return from Rate Base** | 214,778,408 | 89,144,203 | 15,424,060 | 110,210,145 |
| *(Total Rate Base * Rate of Return)* | | | | |
| **Total Cost** | 1,740,795,561 | 1,001,785,981 | 77,259,995 | 661,749,585 |
| *(Total Operating Expenses + Return from Rate Base)* | | | | |
| Total Load (MWh) | | 20,465,557 | | |
| 5% Distribution Losses (MWh) | | 1,023,278 | | |
| **Average System Cost ($/MWh)** | | **50.21** | | |
| *(Total Production and Transmission Costs) / (Total Load + Distribution Losses)* | | | | |

# Table 7.6
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | Puget (PSE) |
| Date Filed: | 4/18/2007 |
| Year/Quarter: | 2006/Q4 |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 1:*** *Plant Investment / Rate Base / Rate of Return* | | | | |
| Total Intanglibe Plant | 29,525,752 | 10,232,574 | 1,982,321 | 17,310,857 |
| Total Production Plant | 1,709,677,644 | 1,709,677,644 | 0 | 0 |
| Total Transmission Plant | 331,209,903 | 0 | 331,209,903 | 0 |
| Total Distribution Plant | 2,892,330,528 | 0 | 0 | 2,892,330,528 |
| Total General Plant | 137,244,959 | 44,403,353 | 8,437,458 | 84,404,148 |
| **Total Electric Plant In-Service** | 5,099,988,786 | 1,764,313,571 | 341,629,682 | 2,994,045,533 |
| **LESS:** | | | | |
| **Total Depreciation and Amortization** | 2,218,809,904 | 833,161,676 | 142,128,036 | 1,243,520,192 |
| **Total Net Plant** | 2,881,178,882 | 931,151,895 | 199,501,646 | 1,750,525,341 |
| *(Total Electric Plant In-Service) - (Total Depreciation & Amortization)* | | | | |
| **Assets and Other Debits (Comparative Balance Sheet)** | | | | |
| Cash Working Capital | 64,283,240 | 33,494,782 | 7,631,995 | 23,156,462 |
| Total Utility Plant | 887,975,267 | 307,248,849 | 44,436,548 | 536,289,869 |
| Total Other Property and Investments | 6,934,092 | 6,934,092 | 0 | 0 |
| Total Current and Accrued Assets | 76,520,443 | 42,451,428 | 3,500,497 | 30,568,517 |
| Total Deferred Debits | 1,136,646,117 | 547,567,933 | 18,841,199 | 570,236,985 |
| **Total Assets and Other Debits** | 2,172,359,159 | 937,697,085 | 74,410,239 | 1,160,251,834 |
| **LESS:** | | | | |
| **Liabilities and Other Credits (Comparative Balance Sheet)** | | | | |
| Total Other Noncurrent Liablities | 0 | 0 | 0 | 0 |
| Total Current and Accrued Liabilities | 71,010,055 | 71,010,055 | 0 | 0 |
| Total Deferred Credtis | 1,178,055,547 | 55,672,768 | 5,253,624 | 1,117,129,154 |
| **Total Liabilities and Other Credits** | 1,249,065,602 | 126,682,823 | 5,253,624 | 1,117,129,154 |
| **Total Rate Base** | 3,804,472,439 | 1,742,166,157 | 268,658,261 | 1,793,648,021 |
| *(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)* | | | | |

***Schedule 2: Weighted Average Cost of Long Term Debt***

| | |
|---|---|
| Long Term Debt | 2,772,999,400 |
| Interest for Year | 167,347,092 |
| **Rate of Return** | 6.03% |
| *(Interest/Long Term Debt)* | |

# Table 7.6
## Average System Cost (ASC) Cookbook Summary

| | |
|---|---|
| Utility: | Puget (PSE) |
| Date Filed: | 4/18/2007 |
| Year/Quarter: | **2006/Q4** |

| Account Description | Total | Production | Transmission | Distribution/ Other |
|---|---|---|---|---|
| ***Schedule 3: Expenses*** | | | | |
| Total Production Expense | 1,144,649,016 | 1,144,649,016 | 0 | 0 |
| Total Transmission Expense | 57,969,332 | 0 | 57,969,332 | 0 |
| Total Distribution Expense | 65,438,100 | 0 | 0 | 65,438,100 |
| Total Customer and Sales Expenses | 71,732,129 | 0 | 0 | 71,732,129 |
| Total Administration and General Expenses | 70,097,636 | 18,929,539 | 3,086,629 | 48,081,469 |
| **Total Operations and Maintenance** | 1,409,886,213 | 1,163,578,555 | 61,055,961 | 185,251,698 |
| **Total Depreciation and Amortization** | 167,698,558 | 59,253,464 | 9,749,014 | 98,696,079 |
| ***Schedule 3A Items: Taxes*** | | | | |
| **Taxes Accrued, Prepaid, and Charged During Year** | | | | |
| Total Federal | 137,284,356 | 3,542,995 | 535,549 | 133,205,812 |
| Total State | 252,301,606 | 21,062,677 | 2,182,120 | 229,056,810 |
| Total County and Municipal | 0 | 0 | 0 | 0 |
| **Total Taxes** | 389,585,962 | 24,605,672 | 2,717,669 | 362,262,622 |
| ***Schedule 3B Items: Other Included Items*** | | | | |
| Total Disposition of Plant | (592,824) | (205,084) | (39,711) | (348,029) |
| Total Sales from Resale | 202,397,803 | 202,397,803 | 0 | 0 |
| Total Other Revenues | 55,575,474 | 6,782,726 | 12,367,733 | 36,425,015 |
| **Total Other Included Items** | 257,380,453 | 208,975,445 | 12,328,022 | 36,076,986 |
| ***Schedule 4: Average System Costs*** | | | | |
| **Total Operating Expenses** | 1,709,790,280 | 1,038,462,246 | 61,194,621 | 610,133,413 |
| *(Total O&M + Total Depreciation & Amortization + Total Taxes - Total Other Included Items)* | | | | |
| **Return from Rate Base** | 229,595,217 | 105,137,578 | 16,213,195 | 108,244,445 |
| *(Total Rate Base * Rate of Return)* | | | | |
| **Total Cost** | 1,939,385,497 | 1,143,599,824 | 77,407,816 | 718,377,857 |
| *(Total Operating Expenses + Return from Rate Base)* | | | | |

| | |
|---|---|
| Total Load (MWh) | 21,091,533 |
| 5% Distribution Losses (MWh) | 1,054,577 |
| **Average System Cost ($/MWh)** | **55.13** |

*(Total Production and Transmission Costs) / (Total Load + Distribution Losses)*

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## PART TWO: 2007-2008 LOOKBACK

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## 8. FY 2007-2008 INTRODUCTION

Part Two of the Lookback Study presents BPA's proposal to reform the first two years of its WP-07 rates to be consistent with the Court's recent decisions. BPA believes the basis for the Court's remand of BPA's WP-02 rates would equally apply to the WP-07 rates if BPA did not reform them at this time. BPA's WP-07 rates continued the WP-02 treatment of REP Settlement costs that the Court found improper. To calculate the improperly allocated amounts, BPA must determine the proper amounts to be allocated to preference customers. BPA believes that the proper amounts can be calculated only after determining the appropriate PF Exchange rate for the period. Because the PF Exchange rate determined in the WP-07 rate proceeding was so intertwined with assumptions regarding the REP Settlement Agreement, BPA proposes that the WP-07 PF Exchange must be recalculated.

Part Two sets forth the determination of the PF Exchange rate after removing the effects of the REP settlements. To do so, BPA looks back to 2006 when the final 2007 rates were being determined and excises the REP settlement assumptions from the rate calculations and replaces them with assumptions that conform to an REP consistent with sections 5(c) and 7(b) of the Northwest Power Act. At this time, the only changed condition regards the decision made about the inclusion of the Mid-Columbia resources in the 7(b)(2)(D) resource stack in the WP-02 re-determination. The rate model, as it existed at the time of the Final Proposal in July 2006, was modified to remove these resources and the rates were recomputed to achieve the final PF Exchange rate used in this Lookback Study.

In addition to the PF Exchange rate, the ASCs for each IOU must be determined. Because the REP settlements had attempted to settle disputes regarding various aspects of the REP, ASCs were not filed during the FY 2007-2008 lookback period. BPA therefore has incorporated FERC

Form 1 data into the requirements of the 1984 ASC Methodology and estimated the annual ASCs for each IOU.

# 9. WHOLESALE POWER RATE DEVELOPMENT STUDY, FY 2007-2008

## 9.1 Average System Cost and Exchange Load Forecast for 2007-2008

This section discusses the correction of errors in the area of data inputs, functionalization codes, and the load forecast of total retail load and REP loads of the region's IOUs.

A new forecast of 2007-2008 ASCs have been determined as part of Lookback process. The WP-07 Final Proposal forecast of the 2007-2008 ASCs was revised, as well as the load forecasts for Contract System Load and REP loads. The ASC forecasts and the REP loads are used in the determination of the 2007-2008 PF Exchange rate in this Supplemental Proposal.

Development of the 2007-2013 ASC forecasts is a two-step process. First, base year ASCs are developed for the six IOUs. The base year ASCs for each IOU were developed using 2004 FERC Form 1 filings. Data from the utilities' FERC Form 1s were entered into the Cookbook Model to determine Contract System Costs. The data were analyzed and functionalized in accordance with the 1984 ASCM, much as would have been done in a formal ASC review proceeding.

Second, the Contract System Costs from the 2004 base year ASCs were escalated to forecast Contract System Costs for 2007-2008 plus the four subsequent years for purposes of the section 7(b)(2) rate test. These prospective ASCs were forecast using the ASC Forecast Model.
The same ASC Forecast Model was used in the WP-07 Final Proposal and the Supplemental Proposal. The model was discussed in the Final WP-07 WPRDS, WP-07-FS-BPA-05, Sections 2.19.5 through 2.19.7.

#### 9.1.1 Data Correction for the 2004 Base Year ASC Determination

The revisions to the WP-07 Final Proposal ASC forecasts for 2007-2008 were limited error corrections in four areas: (1) data entry errors; (2) PacifiCorp's state allocation factors; (3) functionalization codes; and (4) Contract System Load and REP load forecasts.

##### 9.1.1.1 Input Data Corrections in the 2004 Base Year ASC Calculation

Data errors were corrected by using the electronic download and transfer to populate the ASC Cookbook. This provided the FERC Form 1 data for each of the IOUs. The ASC Cookbook was revised to include a template that is designed to facilitate the transfer of data from the FERC electronic system. The corrections to the forecast did not include changes to assumptions, or functionalization that were made and discussed in the Supplemental WPRDS, WP-07-E-BPA-49, Section 8.

##### 9.1.1.2 Correction of Errors to the PacifiCorp State Allocation Factors

Errors were corrected in PacifiCorp's 2004 base year ASC that the result of erroneous state allocation factors. The Jurisdictional Cost Allocation Protocol (JCAP) is the procedure developed by PacifiCorp, its state commissions and other interested parties to allocate the non-directly assignable revenues, expenses and plant to PacifiCorp's jurisdictions. It is a listing of the allocation factors for various items in the FERC Form 1 and other items included in state commission rate orders.

The allocation factors determine how assets, liabilities, costs and revenues are to be allocated among the multiple states for purposes of calculating PacifiCorp's revenue requirement and setting retail rates. The allocation factors are also used in the preparation of the annual or semi-annual results of operations filings. For example, the allocation factors would be used to allocate the capital and operating costs of the Jim Bridger generation plant among the various states. PacifiCorp provided an electronic file containing the JCAP allocation factors. This electronic file was used in coordination with PacifiCorp's 2002 Oregon Jurisdiction Results of Operation filing.

The allocation factors in the 2002 Results of Operation filing were matched to line items in PacifiCorp's 2004 base year ASC cookbook. The allocation factors were then applied to the line items in the Cookbook. In addition, specific state related costs were allocated using the PacifiCorp's 2002 Results of Operation filing to develop percentage allocations. These direct allocations included depreciation plant and expenses, taxes and deferred assets that had a sub-account descriptions that indicated a direct allocation.

**9.1.1.3 Corrections of Functionalization Code Errors**

Functionalization codes are the percentage factors that are applied to revenues or costs in the ASC Cookbook Model. The factor assigns the revenues or costs to production, transmission, or distribution, or to combinations thereof.

**9.1.1.3.1 ASC Cookbook Model**

The first correction was to assign the correct functionalization code to each line item in the ASC Cookbook model. Some of the functionalization codes were not consistent with the 1984 ASCM. The corrected functionalization codes were consistently assigned to each of the IOU Cookbook models.

**9.1.1.3.2 Correction of Regulatory Asset Amortization**

Regulatory assets are deferrals of costs or revenues that have been incurred by a utility but have not been recovered in rates. Examples of such assets include deferred power costs and pension benefits. In the WP-07 Final Proposal, regulatory assets were functionalized based on the nature of the asset. For example, a regulatory asset related to deferred recovery of purchase power costs would have been functionalized to production. In addition, regulatory assets were assumed to be amortized over a short period of time.

In the WP-07 Final Proposal, amortization costs were included for selected regulatory assets. After reviewing the FERC Form 1 Depreciation and Amortization expense schedules, it was noted there was no indication that regulatory assets were separately amortized in any of the depreciation schedules. This error was corrected by removing the regulatory amortization from the calculation of the 2004 IOU base year ASCs.

#### 9.1.1.4 2004 Base Year ASC Correction

Data and functionalization codes were corrected to calculate the revised base year ASCs for the IOUs. Table 9.1 shows the WP-07 Final Proposal 2004 base year ASCs and the Supplemental Proposal 2004 base year ASCs for each of the IOUs. Tables for each IOU are available that show the calculation of the Supplemental Proposal 2004 base year ASC calculation, the WP-07 Final Proposal 2004 base year ASC calculation, and an explanation of the error corrections. *See* Lookback Documentation, WP-E-BPA-44A, Section 9.1.

**TABLE 9.1**
**Comparison of Supplemental Proposal 2004 Base Year to Final Proposal 2004 Base Year**

| | Supplemental Proposal | | WP-07 Final Proposal | |
|---|---|---|---|---|
| | ASC ($/MWh) | Exch. Load (MWh) | ASC ($/MWh) | Exch. Load (MWh) |
| Avista | 43.13 | 3,510,227 | 43.01 | 3,510,227 |
| Idaho Power | 35.39 | 6,660,452 | 38.60 | 6,135,452 |
| NorthWestern Energy | 56.30 | 836,111 | 58.08 | 859,453 |
| PacifiCorp (regional) | 37.79 | 8,767,857 | 40.15 | 10,058,325 |
| Portland General | 44.80 | 7,716,910 | 47.32 | 7,633,624 |
| Puget Sound | 44.73 | 11,066,787 | 48.41 | 10,058,203 |

#### 9.1.1.5 Load Forecast Corrections

In the WP-07 Final Proposal, it was incorrectly assumed that internal BPA-generated forecasts of total retail load for the IOUs did not include distribution losses. The 1984 ASCM specifies that Contract System Load includes distribution losses. Therefore, total retail load forecasts were increased by a 5 percent distribution loss factor to determine Contract System Load. It was subsequently determined that the total retail load forecasts included a 7 percent distribution loss factor; thus the WP-07 Final Proposal, in fact, overstated Contract System Load by using a 12.4 percent loss factor.

For this Supplemental Proposal, the load forecast was corrected by the following:

- First, the total retail load forecast was multiplied by 93 percent. This restated the load forecast to the end-use level.
- Then, the 5 percent distribution loss factor was applied to increase the loads for use as Contract System Load.

Table 9.2 restates the ASCs and now includes the Contract System Load forecasts for the WP-07 Final Proposal and the Supplemental Proposal.

**TABLE 9.2**
**Comparison of Supplemental Proposal 2004 Base Year**
**to Final Proposal 2004 Base Year**

| | Supplemental Proposal | | WP-07 Final Proposal | |
|---|---|---|---|---|
| | ASC ($/MWh) | CSL (MWh) | ASC ($/MWh) | CSL (MWh) |
| Avista | 43.13 | 8,795,447 | 43.01 | 8,795,447 |
| Idaho Power | 35.39 | 13,901,568 | 38.60 | 13,901,568 |
| NorthWestern Energy | 56.30 | 6,862,353 | 58.08 | 6,862,353 |
| PacifiCorp (regional) | 37.79 | 21,479,607 | 40.15 | 22,561,484 |
| Portland General | 44.80 | 18,652,345 | 47.32 | 18,652,345 |
| Puget Sound | 44.73 | 20,870,630 | 48.41 | 20,870,630 |

### 9.1.2 2007-2013 ASC Forecasts

Table 9.3 and 9.4 below show the 2007-2008 ASCs that were used in the WP-07 Final Proposal as well as the revised 2007-2013 ASCs for the IOUs.

**TABLE 9.3**
**Comparison of Supplemental Proposal 2007-2008 Exchange Loads**
**to Final Proposal 2007-2008 Exchange Loads**

| | Supplemental Proposal | | WP-07 Final Proposal | |
|---|---|---|---|---|
| | 2007 (MWh) | 2008 (MWh) | 2007 (MWh) | 2008 (MWh) |
| Avista | 3,824,029 | 4,085,388 | 3,897,357 | 4,184,196 |
| Idaho Power | 7,218,345 | 7,234,428 | 7,380,466 | 7,401,546 |
| NorthWestern Energy | 961,972 | 982,688 | 961,972 | 1,010,998 |
| PacifiCorp (regional) | 9,463,011 | 10,644,572 | 9,579,971 | 10,776,134 |
| Portland General | 8,286,384 | 9,242,122 | 8,377,545 | 9,484,296 |
| Puget Sound | 11,746,838 | 11,189,178 | 11,894,349 | 11,215,422 |

**TABLE 9.5.1**
**Revised 2004-2013 ASC Forecasts**

| | Avista | | Idaho Power | |
|---|---|---|---|---|
| | ASC ($/MWh) | Exch. Load (MWh) | ASC ($/MWh) | Exch. Load (MWh) |
| 2004 | 43.13 | 3,510,227 | 35.39 | 6,660,452 |
| 2005 | 43.03 | 3,590,509 | 35.24 | 6,538,585 |
| 2006 | 44.06 | 3,756,579 | 36.93 | 7,038,389 |
| 2007 | 45.37 | 3,824,029 | 38.26 | 7,218,346 |
| 2008 | 47.02 | 3,897,357 | 39.61 | 7,380,466 |
| 2009 | 48.00 | 3,981,477 | 40.57 | 7,543,106 |
| 2010 | 48.95 | 4,064,974 | 41.59 | 7,707,308 |
| 2011 | 50.06 | 4,146,629 | 42.71 | 7,884,371 |
| 2012 | 51.31 | 4,218,112 | 43.82 | 8,030,291 |
| 2013 | 52.58 | 4,263,887 | 44.85 | 8,099,305 |

**TABLE 9.5.2**
**Revised 2004-2013 ASC Forecasts**

| | NorthWestern | | PacifiCorp | |
|---|---|---|---|---|
| | ASC ($/MWh) | Exch. Load (MWh) | ASC ($/MWh) | Exch. Load (MWh) |
| 2004 | 56.30 | 836,111 | 37.79 | 8,767,757 |
| 2005 | 53.86 | 847,092 | 32.53 | 8,960,693 |
| 2006 | 54.95 | 898,218 | 33.95 | 9,251,568 |
| 2007 | 56.50 | 951,068 | 35.61 | 9,463,011 |
| 2008 | 59.18 | 961,972 | 37.45 | 9,579,971 |
| 2009 | 60.53 | 965,929 | 38.29 | 9,658,348 |
| 2010 | 61.73 | 974,699 | 39.05 | 9,762,851 |
| 2011 | 63.08 | 982,866 | 39.94 | 9,875,253 |
| 2012 | 64.39 | 994,162 | 40.98 | 10,033,223 |
| 2013 | 65.76 | 999,297 | 42.04 | 10,188,763 |

**TABLE 9.5.3**
**Revised 2004-2013 ASC Forecasts**

| | Portland General ASC ($/MWh) | Portland General Exch. Load (MWh) | Puget Sound ASC ($/MWh) | Puget Sound Exch. Load (MWh) |
|---|---|---|---|---|
| 2004 | 44.80 | 7,716,910 | 44.73 | 11,066,787 |
| 2005 | 44.19 | 7,766,126 | 45.62 | 11,382,320 |
| 2006 | 45.46 | 8,049,271 | 46.61 | 11,674,554 |
| 2007 | 47.55 | 8,286,384 | 47.58 | 11,746,838 |
| 2008 | 50.10 | 8,377,545 | 48.60 | 11,894,349 |
| 2009 | 51.13 | 8,469,639 | 49.53 | 12,057,336 |
| 2010 | 51.87 | 8,562,004 | 50.51 | 12,214,852 |
| 2011 | 52.84 | 8,651,356 | 51.65 | 12,365,385 |
| 2012 | 54.14 | 8,788,009 | 52.89 | 12,477,488 |
| 2013 | 55.49 | 8,868,995 | 54.16 | 12,586,358 |

## 9.2 Cost Allocation and Rate Design Implementation

### 9.2.1 Ratemaking Sequence

The ratemaking sequence used in the FY 2007-2008 Lookback is the same as was used in the WP-07 Final Proposal except that the Subscription Strategy section is no longer necessary. The FY 2007-2008 Lookback ratemaking includes a COSA and a series of Rate Design Step adjustments using the same RAM2007 model used in the WP-07 Final Proposal. This model provides a determination of rates for the FY 2007-2008 time period. In an additional table, developed for this Lookback Study, the PF Exchange rate is then used to calculate the level of IOU REP benefits for FY 2007 and FY 2008.

BPA's WP-07 reformed ratemaking methodology includes a COSA, a series of Rate Design Step adjustments, and a Slice Product Separation Step. The COSA assigns responsibility for BPA's generation revenue requirement to the various classes of service in accordance with generally accepted ratemaking principles and in compliance with statutory directives governing BPA's ratemaking. The Rate Design Step adjustments to the allocated costs derived in the COSA are necessary to ensure that BPA recovers its test period revenue requirement while following its statutory rate directives. The Slice Product Separation Step separates out the PF Slice product firm loads, allocated costs, and allocated revenue credits from the overall non-Slice PF loads, allocated costs, and allocated revenue credits. This ratemaking sequence is programmed into a spreadsheet model, RAM2007, for purposes of calculating BPA's requirement power rates.

**9.2.2 Cost of Service Analysis (COSA)**

The COSA allocates the test period generation revenue requirement to BPA customer classes determined in the Final Revenue Requirement Study, WP-07-FS-BPA-02, without revisions. The COSA apportions or "allocates" the test period generation revenue requirement among classes of service based on the principles of cost causation. The relative use of resources, services, or facilities among customer classes is identified and costs are generally allocated to customer classes in proportion to each class's use. Cost allocation also is based on the priorities of service from resource pools to rate pools provided in section 7 of the Northwest Power Act.

BPA uses three major ratemaking steps to complete the process of determining BPA's total cost of service for power rates: (1) *functionalization* of costs between generation and transmission to develop the generation revenue requirement; (2) *classification* of costs between demand, energy, and load variance; and (3) *allocation* of costs to classes of service.

In the Lookback for FY 2007-08, the PF Exchange power rate is recalculated using REP costs in place of the REP settlement costs. Functionalization of costs between generation and transmission is performed in conjunction with the development of BPA's total revenue requirements and only those costs assigned to the Power function are included in the revenue requirement. The one exception is for gross exchange resource costs. These costs are so that only the power portion is subject to the power cost rate design steps; the costs functionalized to transmission are then reincorporated after the rate design steps are completed. The remaining steps to determine BPA's cost of service for wholesale power – classification and allocation of costs – are performed in the COSA portion of the WPRDS. *See* Lookback Documentation, WP-07-E-BPA-44A, Section 9.2.

#### 9.2.3 Power Revenue Requirement

The Bonneville Project Act, the Flood Control Act of 1944, the Transmission System Act, and the Northwest Power Act provide guidance regarding BPA ratemaking. The Northwest Power Act requires BPA to set rates that are sufficient to recover, in accordance with sound business principles, the cost of acquiring, conserving, and transmitting electric power, including amortization of the Federal investment in the FCRPS over a reasonable period of years, and the other costs and expenses incurred by the Administrator. 16 USC § 839e(a)(1).

The Final Revenue Requirement Study, WP-07-FS-BPA-02, is based on generation revenue and cost estimates for a three-year test period, FY 2007-2009. The revenue requirement from the Revenue Requirement Study is adjusted in the COSA for projected balancing purchase power costs, system augmentation costs, and the gross REP costs functionalized to power. The adjusted annual Power function revenue requirements used for rate calculations are shown in the WPRDS. *See* Lookback Documentation, WP-07-E-BPA-44A, Tables 9.2.3.1 (COSA 06 FY 2007) through 9.2.3.3 (COSA 06 FY 2009). The functionalization of the gross REP costs is shown in the Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.3.4 (COSA 07). The total adjusted functionalized revenue requirements for the three-year period are shown in the Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.3.5 (COSA 08).

##### 9.2.3.1 Revenue Requirement Study

In compliance with a FERC order, BPA has prepared a power repayment study specifically for the generation function. *See U.S. Department of Energy – Bonneville Power Admin.,* 26 FERC

¶ 61,096 (January 27, 1984). All costs functionalized to generation are used to develop the generation revenue requirement, which is recovered through FCRPS power rates.

The Final Revenue Requirement Study, WP-07-FS-BPA-02, also includes demonstrations to show that revenue from the proposed rates is adequate to recover all generation related costs of the FCRPS in the rate period and over the repayment period (revised revenue test).

**9.2.3.2 Power Purchases in the COSA**

Three categories of purchased power are included in the COSA. These are: (1) purchased power; (2) balancing power purchases; and (3) system augmentation. Gross REP costs, while portrayed in section 5(c) of the Northwest Power Act as a purchase of power by BPA, are not included in the categories.

**9.2.3.2.1 Purchased Power**

The purchased power costs reflect the acquisition of power through renewable energy, wind, geothermal, and competitive acquisition programs. Costs of purchased power are included in the new resources resource pool. *See* Lookback Documentation, WP-07-E-BPA-44A, Tables 9.2.3.1, 9.2.3.2, and 9.2.3.3 (COSA 06 for FY 2007-2009).

**9.2.3.2.2 Balancing Power Purchases**

The costs of power purchases and storage required to meet firm deficits on a less-than-annual basis are included in the category of balancing power purchases. Projected balancing power purchases are needed to serve firm loads in months other than the spring fish migration period under some water conditions. The value that is used in the revenue requirement is the expected value over 50 water conditions. This balancing power purchase expense estimate is developed in the Risk Analysis Study (using RiskMod) to reflect projected operation of the FCRPS. *See* Final

Risk Analysis Study, WP-07-FS-BPA-04. For this Lookback analysis for FY 2007-08, the balancing purchases amounts have not been changed from those in the WP-07 Final Proposal. *See* Final WPRDS Documentation, WP-07-FS-BPA-05A, Section 3.4. Costs of balancing power purchases are characterized as FBS replacements and, as such, are included in – and allocated as – FBS costs. *See* Lookback Documentation, WP-07-E-BPA-44A, Tables 9.2.3.1, 9.2.3.2, and 9.2.3.3 (COSA 06) for FY 2007-2009.

**9.2.3.2.3 System Augmentation**

BPA also has need to acquire annual amounts of power beyond the inventory represented by the FCRPS and balancing power purchases. These acquisitions are defined as system augmentation and are used to meet customer firm power loads in excess of firm system resources on an annual basis. System augmentation purchases are characterized as FBS replacements and are allocated as FBS costs. For this Lookback analysis for FY 2007-2008, the system augmentation purchases amounts have not been changed from those in the WP-07 Final Proposal. System augmentation costs are shown in the Lookback Documentation, WP-07-E-BPA-44A, Tables 9.2.3.1, 9.2.3.2, and 9.2.3.3 (COSA 06) for FY 2007-2009.

**9.2.4 Functionalization of Residential Exchange Program Costs**

In the COSA, the gross REP cost is based on exchanging utilities' ASCs and the amount of their exchange loads. ASCs include the resource costs associated with serving an exchanging utility's load. The 1984 ASCM specifies what constitutes resource costs, but simply stated, they include most power costs and certain transmission costs. Since the ASCs include transmission costs, the gross costs of the exchange include transmission costs. Therefore, some of the gross costs of the exchange are functionalized to transmission. The rate design adjustments that follow the COSA in BPA's ratemaking sequence use the results of the COSA on the revenue requirement functionalized to power. The REP cost that is used in the COSA includes energy costs, demand costs, and transmission costs, which are functionalized to generation so that the gross REP costs are treated the same as other Power function costs as they go through the rate design adjustment process. The functionalization of REP costs is shown in the Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.3.4 (COSA 07).

### 9.2.5 Classification

Classification in the WPRDS apportions generation costs between the demand, energy, and load variance components of electric power. This classification of the generation revenue requirement is shown in the Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.3.5 (COSA 08).

The classification methodology BPA uses is generally based on the marginal costs of the components of power and generally accepted ratemaking procedures. However, in the WP-07 Final Proposal, rates were determined based on the Partial Resolution of Issues, making classification unnecessary for this rate period. *See* Supplemental WPRDS, WP-07-E-BPA-49, Attachment 1.

### 9.2.6 Functionalized and Classified Revenue Credits

The revenue credits described here are functionalized to generation and classified to energy. Most of these revenue credits are associated with the operation of FBS resources and have the effect of reducing the FBS resource costs to be recovered by BPA's power rates.

#### 9.2.6.1 Downstream Benefits and Pumping Power Revenues

Downstream benefits and pumping power revenues are payments from the sale of Reserve Energy, irrigation pumping power, and revenue from owners of projects downstream to the Corps and Reclamation for benefits received (*i.e.,* additional generation) from the storage reservoirs owned by the Corps and Reclamation. Reserve energy and irrigation pumping power revenue is earned through the year, and paid at the end of the year directly to the Treasury by the Corps and by Reclamation. These revenues are not subject to revision through BPA's rate processes and hence become a revenue credit. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.3.6 (COSA 09).

**9.2.6.2 Section 4(h)(10)(C) Credits**

Section 4(h)(10)(c) credits are available from the Treasury to compensate BPA for its direct program fish and wildlife expense and capital costs and hydro system operation costs incurred for fish migration attributable to the non-power portions of the hydro projects. These credits are 22 percent of these costs. This revenue credit is an estimate of what BPA would receive on average over a range of 50 different water conditions. The actual credit is determined after each year is complete. The operation costs vary with water conditions. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.3.6 (COSA 09).

**9.2.6.3 Colville Credit**

The Colville credit is a Treasury credit BPA receives as a result of a settlement of claims associated with the development of Grand Coulee Dam. The credit is a predetermined amount fixed by legislation. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.3.6 (COSA 09).

**9.2.6.4 Energy Efficiency Revenues**

This credit is for reimbursable expenses arising from the activities of BPA's Energy Services Business. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.3.6 (COSA 09).

#### 9.2.6.5 Miscellaneous Revenues

This credit represents estimated revenues from contract administration, late fees, interest on late payments, and mitigation payments. These fees are not subject to changes in BPA's ratemaking processes. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.3.6 (COSA 09).

#### 9.2.6.6 Reserve Product Revenues

*See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.3.4 (COSA 09).

#### 9.2.6.7 Green Tag Revenues

Green energy premiums (GEP) result from BPA sales of Environmentally Preferred Power (EPP) and renewable energy certificates (REC). The revenues depend on actual wind and renewable project output included in the FCRPS. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.3.4 (COSA 09).

#### 9.2.6.8 Power Services Ancillary and Reserve Services Revenues Credits

Power Services, in the course of marketing power, generates transmission-related revenues and credits. The revenues and credits are predominantly revenues associated with providing ancillary and reserve services from the FCRPS. *See* Section 4 of the Final WPRDS, WP-07-E-BPA-05A. The revenues and credits are classified to energy and are used reduce the FBS resource costs to be recovered by BPA's power rates. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.3.6 (COSA 09).

### 9.2.7 Allocation

Allocation is the apportionment of costs to customer classes. Allocation is performed by determining the relative sizes of resource pools and rate pools pursuant to the rate directives contained in section 7 of the Northwest Power Act. Rate pools are groupings of customer classes (sales or loads) for cost allocation purposes. BPA groups its loads into the "Priority Firm," "Industrial Firm," and "All Other" categories corresponding to sections 7(b), 7(c), and 7(f) of the Northwest Power Act. The resource pools are those identified in the Northwest Power Act as the FBS, REP, and new resources resource pools. Costs associated with each of these respective resource pools are grouped together to facilitate allocation. The sizes of the rate and resource pools are determined from forecast load and resources presented in the Final Load Resource Study, WP-07-FS-BPA-01.

The Northwest Power Act established three rate pools. The 7(b) rate pool includes public body and cooperative (collectively, COUs), and Federal agency sales under section 5(b) of the Northwest Power Act, as well as the sales to utilities participating in the REP established in section 5(c) of the Northwest Power Act. The 7(c) rate pool includes sales to BPA's DSI customers under section 5(d) of the Northwest Power Act. The 7(f) rate pool includes all power BPA sells section 5(f) of the Northwest Power Act. Subsequent to 1985, with the implementation of the directives of section 7(c)(2) of the Northwest Power Act, BPA has had, for all practical purposes, only two rate pools: the 7(b) rate pool and all other loads.

In the Lookback Study, the FBS resource pool consists of the following resources: (1) the FCRPS hydroelectric projects; (2) resources acquired by the Administrator under long-term contracts in force on the effective date of the Northwest Power Act; and (3) replacements for reductions in the capability of the above resource types. Costs expected to be incurred during the rate period for replacement resources were included in the FBS resource pool. *See* Final Revenue Requirement Study Documentation, WP-07-FS-BPA-02A. In addition to long-term resource acquisitions, short-term power purchases are made during the rate period. These short-term power purchases augment the Federal system to achieve load/resource balance on an annual basis as well as balance the Federal system to provide operational flexibility and provide for certain fish mitigation measures on a monthly and daily basis. The costs of such balancing purchases as well as the cost of system augmentation to ensure load/resource balance are considered to be FBS costs and are allocated as such.

### 9.2.7.1 Power Cost Allocations

The process for allocating power costs begins with an examination of critical period firm loads and resources. A ratemaking load and resource balance for each year of the test period is then constructed from the Final Load Resource Study, WP-07-FS-BPA-01, and other data. From this ratemaking load and resource balance, service to each of the three rate pools from each of the resource pools is determined for the rate test period. Table 9.2.4.1 (ALLOCATE 01) shows the ratemaking energy loads and resources by pools. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.4.1 (ALLOCATE 01).

### 9.2.7.2 Energy Allocation Factors

When service from each resource pool to each class of service has been identified, the amounts of such service are the allocation factors for the costs of the resource pool. Resource pool costs are allocated to classes of service based on the proportions of their identified use of the resource pools to the total size (use) of the resource pool. The annual energy allocation factors for each resource pool are shown in the Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.4.1 (ALLOCATE 01). The Total Usage and Conservation allocation factors are the same and are based on the sum of the FBS, REP, and new resources allocation factors. They are used to allocate costs and rate design adjustments to all firm energy loads. Allocated power costs are shown in the Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.4.2 (ALLOCATE 02).

### 9.2.7.3 Other Cost Allocations

Costs not directly identifiable with rate pools, resource pools, or transmission costs allocated to PBL are allocated as described in the following sections.

#### 9.2.7.3.1 Conservation Costs

The Northwest Power Act requires BPA to treat cost-effective conservation as an electric power resource in planning to meet the Administrator's obligations to serve loads. 16 U.S.C. § 839a1(a). The "conservation" line item, as seen in the COSA 06 tables (*see* Lookback Documentation, WP-07-E-BPA-44A, Tables 9.2.3.1 ,9.2.3.2, and 9.2.3.3), includes: (1) debt service for BPA's previous resource acquisition activities; (2) BPA's continuing contributions to the region's market transformation efforts; (3) costs associated with BPA's energy efficiency business; (4) costs associated with the Conservation Rate Credit; and (5) a share of the agency's total planned net revenues. The "Energy Efficiency" revenue line item seen in Table 9.2.3.6 (COSA 09) reflects payments provided by other BPA organizations and Federal agencies for the energy efficiency services delivered. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.3.6 (COSA 09).

#### 9.2.7.3.2 BPA Program Costs

Some of BPA's program costs are not identified directly with any specific resource pool or customer class. An example is the cost of the ratemaking process. The generation portion of these program costs is determined in the Final Revenue Requirement Study, WP-07-FS-BPA-02. The generation portion appears as BPA program costs. These program costs, as seen in Table 9.2.3.5 (COSA 08) are allocated uniformly to all customer classes based on the total usage allocation factors for energy. S*ee* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.3.5 (COSA 08).

#### 9.2.7.3.3 Planned Net Revenues for Risk

PNRR is the amount of net revenues required from power rates to ensure that cash-flows from proposed rates meet fully BPA's probability standard for repaying PBL's portion of Treasury payments on time and in full. PNRR are allocated to resource pools that include Federal capital investments. The methodology for allocating these costs is described and illustrated in the Final Revenue Requirement Study Documentation, WP-07-FS-BPA-02A, Section 2.

The PNRR value found in the COSA 06 tables is the result of an iterative process between the RAM2007, the RiskMod, NORM and the ToolKit models. *See* Final Risk Analysis Study, WP-07-FS-BPA-04. The iteration is initiated with a seed value for PNRR in COSA 06 of the RAM2007. The resultant rates are used in RiskMod to produce probability distributions. These distributions are then used in the ToolKit to produce a new PNRR value for new COSA 06 tables. For this FY 2007-2008 Lookback analysis, the PNRR amounts have not been changed from those in the WP-07 Final Proposal and no iterative process was conducted. For further explanation of this iterative process, *see* Doubleday, *et al.*, WP-07-E-BPA-15.

#### 9.2.8 COSA Results

The COSA results are allocated to the test period revenue requirements for power to classes of service served with firm power. Table 9.2.4.2 (ALLOCATE 02) summarizes the allocated generation power revenue requirement and the total allocated revenue requirement recovered from power classes of service. This includes transmission costs allocated to the Power function. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.4.2 (ALLOCATE 02).

### 9.3 Slice of the System (Slice) Product, Slice Revenue Requirement, and Slice Rate

#### 9.3.1 Explanation of Changes

This section reflects changes to the Slice True-Up process and the treatment of certain expenses and revenue credits due to the Slice Mediation Settlement Agreement (Slice Settlement), which was signed and executed by BPA, the Slice customers, and the Northwest Requirements Utilities on November 22, 2006. In addition, this section reflects the impact on the Slice Revenue

Requirement that resulted from litigation regarding the REP Settlement Agreements and related amendments along with the LRAs with PacifiCorp and Puget Sound Energy.

### 9.3.2 Slice Product Description

The Slice product is a sale of a fixed percentage of the generation output of the FCRPS. It is not a sale or lease of any part of the ownership of, or operational rights to, the FCRPS. The amount of Slice product available to a customer is based upon a Slice customer's annual net firm requirements load, compared to an annual average firm energy load carrying capability of 7,070 aMW, and is shaped to BPA's generation output from the FCRPS. The annual average firm energy load carrying capability of 7,070 aMW was adopted in the WP-02 Final Proposal for the FCRPS, as adjusted by System Obligations and transmission losses. BPA's sale of the Slice product required a commitment by the Slice customer of 10 years, from FY 2002 through FY 2011.

Because the Slice product is calculated as a percentage of the FCRPS generation output, the actual power delivered to the Slice customer varies throughout the year. During certain periods of the year and under certain water conditions, the power delivered exceeds the Slice customer's net firm requirements and may at times exceed the Slice customer's actual firm load. As a consequence, the Slice product entails a sale of both requirements and surplus power products.

### 9.3.3 Slice Revenue Requirement

Each Slice customer pays a percentage of BPA's costs, rather than a set price per megawatt and megawatthour. The Slice customer's obligation to pay is equal to the percentage of the FCRPS generation output that the Slice customer elected to purchase in its 10-year Subscription contract. The costs that the Slice customers pay a percentage of are referred to collectively as the Slice Revenue Requirement. The Slice Revenue Requirement is comprised of all of the line items in

BPA's generation revenue requirement, with certain limited exceptions. *See* Table 9.3.1 for a detailed list of the line items and forecast dollar amounts in the Slice Revenue Requirement.

In 2003, BPA engaged in litigation before the Ninth Circuit concerning the appropriate interpretation and implementation of the Slice rate and the Slice Rate Methodology. *Northwest Requirements Utilities v. Bonneville Power Administration*, Nos. 03-73849, 03-74170, and 04-71311. In that litigation, the Slice customers contended that BPA's Slice True-Up Adjustment Charges for Contract Years 2002 and 2003 were inconsistent with the terms of the Slice contracts, which incorporate language of the Slice rate and Slice Rate Methodology. In July 2006, BPA, the Slice customers, and the Northwest Requirements Utilities agreed on a settlement of the issues and a draft Slice Settlement was submitted to parties' various governing boards, as well as to the U.S. Department of Justice, for review and approval. In addition, BPA released the draft Slice Settlement for public review and comments. BPA received no comments on the draft Slice Settlement. The Slice Settlement (07PB-12273) was approved by the U.S. Department of Justice, and was signed and executed by all parties on November 22, 2006. The Slice Settlement resolved all Slice True-Up disputes for Contract Years 2002-2005, along with previously-disputed substantive issues in a way that will have precedential effect beyond 2005. The Slice Settlement also provides for refunds to Slice customers in the form of credits to their bills and includes a new dispute resolution provision and a Memorandum of Understanding regarding BPA's Debt Optimization Program. In this Supplemental Proposal, BPA is modifying the rate treatment of certain Slice rate and Slice Rate Methodology matters, consistent with the Slice Settlement. *See* Lee, *et al.,* WP-07-E-BPA-59.

**9.3.4 Inclusion and Treatment of Expenses and Revenue Credits**

Because BPA is proposing to make changes to the treatment of particular expenses and revenue credits during the middle of the applicable rate period, it is BPA's intent to make adjustments to the Slice Revenue Requirement and Slice rate on a prospective basis. BPA has made changes to the treatment of particular expenses and revenue credits in the Slice True-Up for FY 2007 and FY 2008, consistent with the Slice Settlement.

The Slice Revenue Requirement includes the same expenses and revenue credits that are included in the Power Services revenue requirement, with certain limited exclusions. In general, there are three types of excluded expenses: (1) power purchases except those associated with the inventory solution; (2) inter-business line transmission costs except those associated with serving BPA System Obligations and GTAs; and (3) PNRR (or its successor risk mitigation tools) and hedging expenses except those hedging expenses associated with the inventory solution.

The following paragraphs clarify the rate treatment of particular items in the Slice Revenue Requirement and Actual Slice Revenue Requirement. The Slice Revenue Requirement includes all the expenses and revenue credits that are the basis for calculating the Slice rate for FY 2007-2008. The expenses and revenue credits included in the Slice Revenue Requirement that is the basis for the FY 2007-2008 Slice rate are forecasts for FY 2007-2009 that were determined in the WP-07 Final Proposal. The Actual Slice Revenue Requirement includes the same expense and revenue credit categories as the Slice Revenue Requirement, but is comprised of the final audited actual expenditures and revenues as reflected on BPA's Power Services financial statements, including any adjustments that result from this proceeding. The Actual Slice Revenue Requirement for a given fiscal year is used as the basis for the calculation of the annual Slice True-Up Adjustment Charge for that fiscal year. *See* Section 9.3.6, for a more detailed description of the Slice True-Up process.

#### 9.3.4.1 Augmentation Expenses

During the prior rate period (FY 2002-2006), BPA supplemented the capability of the FBS to meet the total load placed on BPA (augmentation purchases). These augmentation power purchases were those needed to meet all load service requests made under BPA's Subscription contracts on a planning basis. Conceptually, augmentation purchases are considered to be separate and distinct from "balancing purchases." "Balancing purchases" refer to those purchases used to replace reduced hydro system flexibility due to increased operating constraints and to those purchases needed to serve BPA's load on an hourly and monthly basis. Slice customers do not pay for BPA's "balancing purchases," as the Slice customers face the risk of reduced hydro system flexibility directly and have the obligation to serve their own loads on an hourly and monthly basis.

Slice customers are required to pay their proportionate share of the net cost of all augmentation expenses. The "net cost" of augmentation refers to the costs associated with the purchase of the augmentation power less the associated revenues from the sale of such augmentation power. Slice customers do not receive any power associated with these augmentation purchases.

In the WP-07 Final Proposal, BPA forecast that there would be augmentation expenses during the FY 2007-2009 rate period. BPA identified three distinct types of augmentation expenses in the FY 2007-2009 rate period: (1) "residual" augmentation expenses; (2) "deferred" augmentation expenses; and (3) other augmentation expenses.

"Residual" augmentation expenses, are the expenses associated with augmentation purchases that carried over from the FY 2002-2006 rate period into FY 2007-2009. When BPA purchased power on the market to meet its load obligations for the FY 2002-2006 rate period, some of the purchases extended to the end of the 2006 calendar year, rather than ending at the close of the rate period (September 30, 2006). The average megawatts associated with the residual augmentation purchases were needed to meet BPA's load obligation for FY 2007. Slice customers paid their proportionate share of the "net cost" of these residual augmentation purchases. For the net cost calculation, BPA assumes that it will purchase 105 aMW of residual augmentation power for a total of $49 million in FY 2007. *See* Final WPRDS Documentation, WP-07-FS-BPA-05A, Table 3.6.2, at 58. This expense ended in FY 2007.

The revenues associated with the sale of the residual augmentation power were estimated, based on the average PF rate for power and multiplied by the amount of power that would be sold, which was 105 aMW in FY 2007. The average PF rate determined in the WP-07 Final Proposal was 27.33 mills per kWh. BPA subtracted the expected revenues from the purchase expense to calculate the net cost of the residual augmentation purchases for FY 2007. The net cost of the residual augmentation purchases for FY 2007 was not subject to the Slice True-Up process.

The second type of augmentation expenses are those referred to as "deferred" augmentation. This category contains those augmentation expenses incurred during the FY 2002-2006 rate period, but the payment of which was deferred to FY 2007-2009 and beyond. The deferred augmentation expenses were associated with payment of a "Reduction of Risk Discount" to Puget Sound Energy and PacifiCorp. The *Proposed Contracts or Amendments to Existing Contracts with the Regional Investor-Owned Utilities regarding the Payment of Residential and Small-Farm Consumer Benefits under the Residential Exchange Program Settlement Agreements FY 2007-2011 Administrator's Record of Decision* (May 25, 2004) (IOU REP Settlement ROD) modified approximately $200 million in Reduction of Risk Discount payments to Puget Sound Energy and PacifiCorp. Puget Sound Energy and PacifiCorp agreed to forgo collection of the one-half of the Reduction of Risk Discount ($100 million) and deferred collection of the balance ($100 million) until the FY 2007-2011 period. With interest payments, this totals to $115 million of deferred augmentation expenses for FY 2007-2011, which will be recovered through PF rates in amounts of $23 million per year. *See* Table 9.3.1.

As the result of a series of recent decisions by the Ninth Circuit regarding the REP settlements, BPA must make modifications to the deferred augmentation expenses. In response to these decisions by the Ninth Circuit, BPA is in the process of revising this expense for FY 2009 in its Supplemental Proposal, but this revision will not affect the Slice Revenue Requirement that is the basis for the FY 2007-2008 Slice rate. In the WP-07 Final Proposal, these estimates were not subject to the annual Slice True-Up, as they were set by contract and were not expected to change. However, due to the invalidation of the REP Settlement Agreements by the Ninth Circuit, the expenses are not being incurred. BPA proposes to make adjustments either through the Slice rate or Slice True-Up process that is commensurate with the adjustments made to non-Slice rates.

The third category of expenses is "other" augmentation expenses. This category includes the expenses associated with augmentation purchases that BPA needed to meet its load obligation during FY 2007-2009. In the WP-07 Final Proposal, BPA forecast the augmentation amounts for FY 2007, FY 2008, and FY 2009 to be 179 aMW, 179 aMW, and 270 aMW, respectively. *See* Final Load Resource Study, WP-07-FS-BPA-01, at 60. Slice customers are obligated to pay their proportionate share of the "net cost" of these augmentation purchases. For theWP-07 Final Proposal, BPA assumed that it would purchase augmentation power in FY 2007 at $61.90 per MWh, in FY 2008 at $60.40 per MWh, and in FY 2009 at $62.10 per MWh. *See* Final WPRDS Documentation, WP-07-FS-BPA-05A, Table 3.6.2, at 60. The revenues associated with the sale of augmentation power were estimated, based on the projected PF rate for power and multiplied by the amount of power that would be sold (179 aMW, 179 aMW, and 270 aMW, respectively for FY 2007, FY 2008, and FY 2009). The projected PF rate was 27.33 mills per kWh. The expected revenues were subtracted from the forecast purchase expense to calculate the net cost of the augmentation purchases for FY 2007-2009 determined in the WP-07 Final Proposal. The net cost of augmentation power for FY 2007-2009 was not subject to the Slice True-Up process.

#### 9.3.4.2 Conservation Augmentation (ConAug)

ConAug was the conservation component of BPA's inventory solution in the WP-02 rate case. ConAug was a resource acquisition effort to purchase conservation measures to reduce BPA's load obligation.

The annual costs of ConAug were estimated and included in the augmentation expenses for the FY 2002-2006 Slice Revenue Requirement. Since it was not known specifically during the WP-02 rate case how the ConAug program would be implemented, the annual costs were derived as if the load reduction was equivalent to a power purchase. The estimate of ConAug costs was based on the assumption that 20 aMW of ConAug would be purchased each year during the FY 2002-2006 rate period. The cost of this power was estimated to be 28.1 mills/kWh plus 10 percent, or 30.9 mills/kWh and included it as part of the Slice Revenue Requirement.

In the WP-02 rate case, BPA set the ConAug expense as a fixed amount that was not subject to the Slice True-Up. This fixed amount was limited to the first 20 aMW of ConAug acquired each year during the FY 2002-2006 rate period. Slice customers paid their share of the estimated costs of 100 aMW of ConAug during the FY 2002-2006 rate period. If BPA acquired more than 20 aMW during any given year, those costs would be handled through the Load-Based CRAC and included in related charges to both Slice and non-Slice customers.

BPA independently decided to capitalize the costs of actual ConAug acquisitions. As a result there are annual amortization expenses associated with ConAug investments from the FY 2002-2006 rate period that carry over into FY 2007-2009. *See* Final Revenue Requirement Study Documentation, WP-07-FS-BPA-02A, Table 3F, at 51, line 6. These investments are amortized over the term of the Subscription contracts and are not fully amortized until FY 2011. However, Slice customers will not pay for these ConAug amortization costs in the FY 2007-2009 rate period, because Slice customers paid a forecast of ConAug costs as if they were incurred as annual expenses. Therefore, the amortization will be excluded from the Slice Revenue Requirement and the Actual Slice Revenue Requirement.

**9.3.4.3 IOU Residential Exchange Program Settlement Benefits**

In the WP-07 Final Proposal, Slice customers were obligated to pay their proportionate share of the REP settlement benefits payments to PNW IOUs during the FY 2007-2009 rate period. As a result of a series of decisions by the Ninth Circuit, the underlying REP Settlement Agreements were determined to be void and, therefore, will no longer be part of the Slice Revenue Requirement.

There were two aspects of the REP settlement payments that were included in the Slice Revenue Requirement determined in the WP-07 Final Proposal: (1) the interest of the balance of the FY 2003 $55 million deferral for all IOUs not repaid as of September 30, 2006, and (2) REP settlement benefits to all six IOUs applied to the FY 2007-2011 period, specified under their contracts or contract amendments titled *Agreement Regarding Payment of Residential Exchange Program Settlement Benefits during FY 2007-2011*.

The balance of the $55 million payment deferral for all IOUs not repaid as of September 30, 2006 was accounted for as an expense in FY 2003, and the Slice customers paid their proportionate share of this expense through the True-Up Adjustment in that year. Therefore the balance still owed on September 30, 2006, was not included as an expense in the Slice Revenue Requirement for purposes of calculating the Slice rate, nor was it accounted for as an expense in the Actual Slice Revenue Requirement for the FY 2007-2008 period for purposes of the annual Slice True-Up.

The interest associated with the $55 million, forecast to be approximately $1 million annually, was included in the FY 2007-2009 Slice Revenue Requirement determined in the WP-07 Final Proposal for purposes of calculating the Slice rate. The interest also was to be accounted for as an expense in the Actual Slice Revenue Requirement for calculation of the True-Up Adjustment Charge in the FY 2007-2009 period. Because of the decisions by the Ninth Circuit, this expense has been eliminated, and any necessary adjustment for FY 2007 and FY 2008 will be addressed through the Slice True-Up for FY 2008.

The second aspect to the payments to the IOUs was the "IOU REP Settlement benefits to all six IOUs." In May 2004, all six IOUs signed contracts or contract amendments entitled, "Agreement Regarding Payment of Residential Exchange Program Settlement Benefits during FY 2007-2011." These contracts or contract amendments apply to FY 2007-2011, and specify that BPA will provide monetary benefits rather than physical power to each of the six IOUs. The contracts or contract amendments also specify a mark-to-market methodology for determining the amount of the monetary benefits based upon the difference between a market price and the lowest-cost PF rate. *See* Petty*, et al.,* WP-07-E-BPA-11.

The amount of the REP settlement benefits to all six IOUs was not fixed but would change each year depending on the difference between an independent market price forecast and the lowest-cost PF rate (including any CRAC or DDC). In addition to the new methodology, the FY 2007-2011 contracts or contract amendments provide both a floor and a cap for benefit levels. The REP settlement benefits to be paid by BPA during any fiscal year had a floor of $100 million and a cap set at $300 million. BPA forecast the benefit amount to be at or near the cap during all three years of the FY 2007-2009 rate period and included this amount in the Slice Revenue Requirement that was determined in the WP-07 Final Proposal. *See* Table 9.3.1, line 28.

Because of the decisions by the Ninth Circuit, this expense has been eliminated, and any necessary adjustment for FY 2007 and FY 2008 will be addressed through the Slice True-Up for FY 2008.

**9.3.4.4 Cost of the Residential Exchange for Public Utilities**

Slice customers are responsible for paying their proportionate share of the net costs of the REP for public utilities. The net cost of the REP for public utilities was calculated by subtracting the gross exchange revenues from the gross exchange expenses. *See* Final WPRDS Documentation, WP-07-FS-BPA-05A, Table 3.6.2. An amount of net costs of the REP for public utilities was forecast for each year of the FY 2007-2009 rate period, and is included in the Slice Revenue Requirement. The actual costs of the REP for public utilities in any year will be included in the Actual Slice Revenue Requirement for that year, for purposes of calculating the Slice True-Up.

**9.3.5 Bad Debt Expense**

The Slice Revenue Requirement contained a line item labeled "Bad Debt Expense." "Bad Debt Expense" is a line item in Power Service's Statement of Revenues and Expenses. While no amounts were forecast for bad debt expense for the FY 2007-2009 period, the Actual Slice Revenue Requirement will contain the actual amount accounted for as bad debt expense, except for bad debt expense associated with the sale of energy to any customer that purchases exclusively under the FPS-07 rate schedule, as established in the *Partial Resolution of Issues.* However, any bad debt expense associated with the sale of energy under both the PF-07 and FPS-07 or just the PF-07 rate schedule, will be included in the Actual Slice Revenue Requirement for Slice True-Up purposes. *See* Evans, *et al.,* WP-07-E-BPA-31, Attachment A, at A-4. Through the annual Slice True-Up, Slice customers paid their proportionate share of the eligible bad debt expenses.

The Slice Settlement contains a provision that addresses the treatment of bad debt related to California Independent System Operator (CAISO) and California Power Exchange (Cal PX). In regards to CAISO and Cal PX bad debt, BPA reversed the True-Up Adjustment charges to Slice customers for the bad debt expense arising out of transactions with the CAISO and Cal PX prior to October 1, 2001. As a result, Slice customers will not receive any future credits for subsequent recovery of any receivables related to amounts previously written off that BPA collects, nor will the Slice customers pay for any future bad debt expense related to write-offs of any outstanding CAISO or Cal PX receivables.

In addition, the Slice Settlement contains a provision that addresses the treatment of bad debt related to DSIs. This provision specifically states that allowances for uncollectible DSI liquidated damages for FY 2002 or prior years will not be included in the Actual Slice Revenue Requirement or Slice True-Up Adjustment Charge. As a result, Slice customers will not receive any future credits for subsequent recovery of any receivables related to amounts previously written off that BPA collects from DSIs.

#### 9.3.5.1 DSI Costs of Service

On June 30, 2005, BPA's Administrator signed the Record of Decision *Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011* (DSI ROD). In this decision, the Administrator determined that BPA would offer 560 aMW of service benefits to the aluminum smelters, capped at an annual cost of $59 million, plus 17 aMW of power to Port Townsend Paper Corporation, for the FY 2007-2011 period. *See* Gustafson, *et al.,* WP-07-E-BPA-17.

These costs are included in the Slice Revenue Requirement and were subject to the annual Slice True-Up. Slice customers paid their proportionate share of these costs.

#### 9.3.5.2 Fish and Wildlife Program Costs

Slice customers are obligated to pay their proportionate share of BPA's direct program costs for fish and wildlife, both BPA's direct program as well as Corps of Engineers and U.S. Bureau of Reclamation costs. Slice customers also experienced their proportionate share of BPA's indirect, or operational, program costs for fish and wildlife directly, through reduced or changed Slice power deliveries.

If BPA's fish and wildlife obligations differed from the forecasts contained in the Slice Revenue Requirement, Slice customers pay their proportionate share of any increase or decrease in fish and wildlife annual expenses through their annual True-Up. Slice customers were affected in real-time for any changes in indirect program costs (*e.g.*, changed operations or increases in spill and flow) for fish and wildlife through changes in their Slice power deliveries.

Slice customers are not subject to either the NMFS FCRPS Biological Opinion (BiOp) (NFB) Adjustment or the Emergency NFB Surcharge. As already mentioned, Slice customers paid their proportionate share of any changes in fish and wildlife annual expenses through their annual True-Up and any indirect program cost changes were experienced through changes in Slice power deliveries.

#### 9.3.5.3 Slice Implementation Expenses

Slice Implementation Expenses are defined as those costs reasonably incurred by Power Services in any Contract Year (same as BPA's fiscal year) for the sole purpose of implementing the Slice product, and that would not have been incurred had Power Services not sold Slice Output under the Block and Slice Power Sales Agreement. Therefore, if Power Services incurs costs during any Contract Year for the purpose of implementing the Slice product, Power Services will account for these as expenses and will charge 100 percent of these expenses to the Slice customers through the annual Slice True-Up.

The Slice Settlement contains a provision that addresses the treatment of Slice Computer Application Project costs. The Slice Settlement states that, consistent with BPA's Software Capitalization Policy or Personal Property Capitalization Policy, any hardware or software acquired for the Slice Computer Application Project and for implementing the Block/Slice PSA will be capitalized over the shorter of a five-year period or the remainder of the Block/Slice contract term, which ends on September 30, 2011. This represents a change from what was proposed in the WP-07 Final Proposal where all Slice Computer Application Project costs were treated as current expenses, rather than capitalized and recovered over a five-year period.

Projections of Slice Implementation Expenses were not included in the Slice Revenue Requirement, and therefore, were not included in the Slice rate for FY 2007-2008. Slice Implementation Expenses in any given Contract Year were accounted for after the audited year-end Actual Slice Revenue Requirement for that Contract Year was available. Slice Implementation Expenses were charged to Slice customers through the annual Slice True-Up for that Contract Year.

**9.3.5.4 Debt Optimization Program**

Through the Debt Optimization program, BPA refinances (extends the maturities of) EN bonds as they come due and repays an equivalent amount of Federal debt. In total, the same amount of debt is repaid that rates were set to recover, but with an emphasis toward repaying Federal debt rather than non-Federal debt. *See* Homenick*, et al.*, WP-07-E-BPA-10, Section 3.

The financial effects from the refinancing and the related additional amortization of Federal debt are properly and fully accounted for in the Actual Slice Revenue Requirement, in accordance with the manner in which they are accounted for in Power Services' statement of revenues and expenses and in the determination of business line financial reserves.

The Debt Optimization program is a BPA debt management policy that affects not only the Slice rate (through the annual True-Up Adjustment Charge), but is a recognized factor of BPA's rate of general application through the implementation of the CRAC. Inclusion of the Debt Optimization program transactions in the annual True-Up Adjustment Charge is recognition of the Slice customers' share of these obligations.

**9.3.5.5 Reinvestment of "Green Tag Revenues" in BPA's Renewable Resources Facilitation and Research and Development**

BPA reinvested what it collectively refers to as "Green Tag revenues" in BPA's renewable resource facilitation and in renewables research and development. These "Green Tag revenues" came from three sources: (1) Green Energy Premium revenues resulting from sales of Environmentally Preferred Power; (2) Green Tag revenues resulting from sales of Renewable Energy Certificates; and (3) revenues from sales of Alternative Renewable Energy to Pre-Subscription power purchasers. BPA did not include the renewables expense associated with the reinvestment of "Green Tag revenues" in the Slice Revenue Requirement nor the Actual Slice Revenue Requirement. *See* WPRDS*,* WP-07-E-BPA-49, Attachment A, at A-4, A-5, Partial Resolution of Issues.

**9.3.5.6 Minimum Required Net Revenues Calculation**

Minimum Required Net Revenues was a component of the annual Generation Revenue Requirement. Minimum Required Net Revenues also was a component of the Slice Revenue

Requirement.  Minimum Required Net Revenues may be necessary to ensure that revenue requirements are sufficient to cover all cash requirements, including annual amortization of the Federal investment as determined in the power repayment studies and any other cash requirements such as payment of irrigation assistance.  *See* Final Revenue Requirement Study, WP-07-FS-BPA-02, at 20, lines 17-21.  BPA determined that the annual amounts for Minimum Required Net Revenue in the Slice Product Costing and True-Up Table should be different than the amounts that appear in the total Generation Revenue Requirement.  These differences are appropriate.  *See* Lee, *et al.,* WP-07-E-BPA-35, at 4, lines 21-24.  The differences are due to one element that is different between the two Minimum Required Net Revenues calculations.  In the total Generation Revenue Requirement, accrual revenues that are included in the revenue forecast must be taken into account.  Since these are non-cash revenues, the Minimum Required Net Revenues calculation must adjust cash from current operations to ensure adequate coverage of the annual cash requirements in order to demonstrate full cost recovery for proposed power rates.  *See* Final Revenue Requirement Study, WP-07-FS-BPA-02, at 28.  These accrual revenues stem from a settlement in which BPA/Power Services received cash payments that, in the accounting treatment, are recognized as revenues on a straight-line basis over the remainder of the term of the settled contracts.  However, these settlements and the associated accrual revenues were not relevant to cost recovery for Slice and do not appear in the calculation of Minimum Required Net Revenues for the Slice Revenue Requirement (which is represented by the Slice Product Costing and True-Up Table).  Due to this difference, the Minimum Required Net Revenues in the Slice Product Costing and True-Up Table, was smaller than the Minimum Required Net Revenues in the total Generation Revenue Requirement.

**9.3.6 Slice Rate**

The Slice Revenue Requirement was the basis for calculating the base Slice rate.  To calculate the Slice rate that was in effect for FY 2007-2008, the total dollar amounts for each fiscal year of the Slice Revenue Requirement were summed and divided by 36 months (the number of months in the three-year rate period FY 2007-2009 for the WP-07 Wholesale Power Rate Final Proposal) and divided by 100 to obtain the base Slice rate per percent of Slice product purchased. *See* Table 9.3.1, line 163. The monthly Slice rate was $1,877,054 per percent Slice product purchased for FY 2007-2008.

### 9.3.7 Slice True-Up

Because the Slice rate is calculated as a uniform monthly rate for the rate period and does not take into account the variability of actual costs from year-to-year, BPA will true-up the difference between the expenses and credits in the average Slice Revenue Requirement for the applicable period upon which the Slice rate is based and the actual expenses and credits in the Actual Slice Revenue Requirement for the applicable fiscal year. The Actual Slice Revenue Requirement for the applicable fiscal year is the sum of the final audited expenditures and revenues as reflected on BPA's Power Services financial statements, corresponding to those Power Service expense and revenue categories that are included in the Slice Revenue Requirement. BPA's financial statements contain expenses and credits that are in accordance with GAAP. Any difference between the Actual Slice Revenue Requirement and the average Slice Revenue Requirement is called the Slice True-Up Amount. The Slice Settlement (*see* Section 9.3.3) specifies that BPA's True-Up calculation will be the Actual Slice Revenue Requirement for the applicable fiscal year minus the **average** Slice Revenue Requirement for the applicable rate period.

A positive or negative result from the calculation resulted in an additional charge or credit to the Slice customer. This additional charge or credit to the Slice customer was known as the Slice True-Up Adjustment Charge (or Credit). Because of the Slice True-Up Adjustment Charge (or Credit), Slice customers paid a percentage of BPA's actual costs, regardless of weather, streamflow, market, or generation output conditions. This assured payment of actual costs mitigates BPA's financial risks in the event that any of these conditions put adverse financial pressure on BPA. The Slice customers' payments through their base Slice rate and the annual True-Up Adjustment Charge mitigates the risk associated with the variability of BPA's expenses and revenue credits (for those expenses included in the Slice Revenue Requirement). The risks associated with the variability of generation output and with the uncertainty of market prices for purchasing or selling power were assumed directly by the Slice customers.

# Table 9.3.1
# Slice Product Costing and True-Up Table

| | ($000s) | Audited Actual Data | FY 2007 forecast | FY 2008 forecast | FY 2009 forecast |
|---|---|---|---|---|---|
| 1 | **Operating Expenses** | | | | |
| 2 | **Power System Generation Resources** | | | | |
| 3 | **Operating Generation** | | | | |
| 4 | COLUMBIA GENERATING STATION (WNP-2) | | 263,669 | 188,688 | 242,902 |
| 5 | BUREAU OF RECLAMATION | | 71,654 | 74,760 | 77,766 |
| 6 | CORPS OF ENGINEERS | | 161,519 | 165,742 | 170,407 |
| 7 | LONG-TERM CONTRACT GENERATING PROJECTS | | 24,932 | 25,314 | 25,751 |
| 8 | **Sub-Total** | | **521,774** | **454,504** | **516,826** |
| 9 | **Operating Generation Settlement Payment** | | | | |
| 10 | COLVILLE GENERATION SETTLEMENT | | 16,968 | 17,354 | 17,749 |
| 11 | SPOKANE GENERATION SETTLEMENT | | 0 | 0 | 0 |
| 12 | **Sub-Total** | | **16,968** | **17,354** | **17,749** |
| 13 | **Non-Operating Generation** | | | | |
| 14 | TROJAN DECOMISSIONING | | 5,400 | 4,700 | 3,100 |
| 15 | WNP-1&3 DECOMISSIONING | | 200 | 200 | 200 |
| 16 | **Sub-Total** | | **5,600** | **4,900** | **3,300** |
| 17 | **Contracted Power Purchases** | | | | |
| 18 | PNCA HEADWATER BENEFIT | | 1,714 | 1,714 | 1,714 |
| 19 | HEDGING/MITIGATION (omit except for those assoc. with inventory solution) | | | | |
| 20 | DSI MONETIZED POWER SALE | | 59,000 | 59,000 | 59,000 |
| 21 | OTHER POWER PURCHASES (short term - omit) | | | | |
| 22 | **Sub-Total** | | **60,714** | **60,714** | **60,714** |
| 23 | **Augmentation Power Purchases** | | | | |
| 24 | AUGMENTATION POWER PURCHASES (omit - calculated below) | | | | |
| 25 | CONSERVATION AUGMENTATION (omit) | | | | |
| 26 | **Residential Exchange/IOU Settlement Benefits** | | | | |
| 27 | PUBLIC RESIDENTIAL EXCHANGE (net costs) | | **6,762** | **6,811** | **6,861** |
| 28 | IOU RESIDENTIAL EXCHANGE | | **301,000** | **301,000** | **301,000** |
| 29 | **Renewable Generation (expenses related to reinvestment removed)** | | **30,289** | **34,719** | **40,835** |
| 30 | **Generation Conservation** | | | | |
| 31 | LOW INCOME WEATHERIZATION & TRIBAL | | 5,000 | 5,000 | 5,000 |
| 32 | ENERGY EFFICIENCY DEVELOPMENT | | 12,885 | 12,908 | 12,933 |
| 33 | ENERGY WEB | | 1,000 | 1,000 | 1,000 |
| 34 | **LEGACY (Until 11/1/03 this was included with line 72)** | | 3,728 | 2,638 | 2,114 |
| 35 | MARKET TRANSFORMATION | | 10,000 | 10,000 | 10,000 |
| 36 | TECHNOLOGY LEADERSHIP | | 1,300 | 1,300 | 1,300 |
| 37 | INFRASTRUCTURE SUPPORT AND EVALUATION | | 1,000 | 1,000 | 1,000 |
| 38 | BI-LATERAL CONTRACT ACTIVITY | | 1,000 | 1,000 | 1,000 |
| 39 | **Sub-Total** | | **35,913** | **34,846** | **34,347** |
| 40 | CONSERVATION RATE CREDIT | | 36,000 | 36,000 | 36,000 |
| 41 | **Power System Generation Sub-Total** | | **1,015,019** | **950,848** | **1,017,632** |
| 42 | | | | | |
| 43 | **PBL Transmission Acquisition and Ancillary Services** | | | | |
| 44 | **PBL Transmission Acquisition and Ancillary Services** | | | | |
| 45 | PBL - TRANSMISSION & ANCILLARY SERVICES | | | | |
| 45a | Canadian Entitlement Agreement Transmission Expenses | | 24,806 | 25,550 | 26,991 |
| 45b | PNCA & NTS Transmission and System Obligaton Expenses | | 1,775 | 1,825 | 1,875 |
| 46 | 3RD PARTY GTA WHEELING | | 47,000 | 47,000 | 48,000 |
| 47 | PBL - 3RD PARTY TRANS & ANCILLARY SVCS | | | | |
| 48 | RESERVE & OTHER SERVICES | | 8,462 | 8,462 | 8,462 |
| 49 | TELEMETERING/EQUIP REPLACEMT | | 200 | 200 | 200 |
| 50 | **PBL Trans Acquisition and Ancillary Services Sub-Total** | | **82,243** | **83,037** | **85,528** |
| 51 | | | | | |
| 52 | **Power Non-Generation Operations** | | | | |
| 53 | **PBL System Operations** | | | | |
| 54 | EFFICIENCIES PROGRAM (omit TMS expenses) | | 0 | 0 | 0 |
| 55 | INFORMATION TECHNOLOGY | | 0 | 0 | 0 |
| 56 | GENERATION PROJECT COORDINATION | | 5,637 | 5,738 | 5,844 |
| 57 | SLICE IMPLEMENTATION (omit - calculated separately) | | | | |
| 58 | **Sub-Total** | | **5,637** | **5,738** | **5,844** |
| 59 | **PBL Scheduling** | | | | |
| 60 | OPERATIONS SCHEDULING | | 8,758 | 9,051 | 9,353 |
| 61 | OPERATIONS PLANNING | | 5,202 | 5,358 | 5,521 |
| 62 | **Sub-Total** | | **13,960** | **14,409** | **14,874** |
| 63 | **PBL Marketing and Business Support** | | | | |
| 64 | SALES & SUPPORT | | 15,884 | 16,278 | 16,745 |
| 64a | Contractual exclusion | | (5,360) | (5,360) | (5,360) |
| 65 | PUBLIC COMMUNICATION & TRIBAL LIAISON | | | | |
| 66 | STRATEGY, FINANCE & RISK MGMT | | 10,965 | 11,359 | 11,771 |
| 67 | EXECUTIVE AND ADMINISTRATIVE SERVICES | | 845 | 840 | 834 |
| 68 | CONSERVATION SUPPORT (EE staff costs) | | 6,441 | 6,692 | 6,953 |
| 69 | **Sub-Total** | | **28,776** | **29,808** | **30,943** |
| 70 | **Power Non-Generation Operations Sub-Total** | | **48,372** | **49,955** | **51,662** |
| 71 | | | | | |
| 72 | **Fish and Wildlife/USF&W/Planning Council** | | | | |
| 73 | **BPA Fish and Wildlife (includes F&W Shared Services)** | | | | |
| 74 | FISH & WILDLIFE | | 143,000 | 143,000 | 143,000 |
| 75 | F&W HIGH PRIORITY ACTION PROJECTS | | | | |
| 76 | **Sub-Total** | | **143,000** | **143,000** | **143,000** |
| 77 | **PBL-USF&W Lower Snake Hatcheries** | | | | |
| 78 | USF&W LOWER SNAKE HATCHERIES | | 18,600 | 19,500 | 20,400 |
| 79 | **PBL - Planning Council** | | | | |
| 80 | PLANNING COUNCIL | | 9,085 | 9,276 | 9,467 |
| 81 | **PBL - ENVIRONMENTAL REQUIREMENTS** | | | | |
| 82 | ENVIRONMENTAL REQUIREMENTS | | 500 | 500 | 500 |
| 83 | **Fish and Wildlife/USF&W/Planning Council Sub-Total** | | **171,185** | **172,276** | **173,367** |
| 84 | | | | | |

# **Table 9.3.1** (continued)
## Slice Product Costing and True-Up Table

| | | | | | |
|---|---|---|---|---|---|
| 84 | | | | | |
| 85 | **BPA Internal Support** | | | | |
| 86 | **CSRS/FERS** | | | | |
| 87 | ADDITIONAL POST-RETIREMENT CONTRIBUTION | 10,550 | 9,000 | 15,375 | |
| 88 | **Corporate Support - G&A (excludes direct project support)** | | | | |
| 89 | CORPORATE G&A | 50,247 | 51,753 | 51,764 | |
| 90 | **TBL Supply Chain - Shared Services** | 368 | 374 | 380 | |
| 91 | **General and Administrative/Shared Services Sub-Total** | **61,165** | **61,127** | **67,519** | |
| 92 | | | | | |
| 93 | **Bad Debt Expense** | | | | |
| 94 | **Other Income, Expenses, Adjustments** | **1,800** | **1,800** | **3,600** | |
| 95 | **Non-Federal Debt Service** | | | | |
| 96 | **Energy Northwest Debt Service** | | | | |
| 97 | COLUMBIA GENERATING STATION DEBT SVC | 195,690 | 217,856 | 218,767 | |
| 98 | WNP-1 DEBT SVC | 147,941 | 165,916 | 163,282 | |
| 99 | WNP-3 DEBT SVC | 151,724 | 160,092 | 153,030 | |
| 100 | EN RETIRED DEBT | | | | |
| 101 | EN LIBOR INTEREST RATE SWAP | | | | |
| 102 | **Sub-Total** | **495,355** | **543,864** | **535,079** | |
| 103 | **Non-Energy Northwest Debt Service** | | | | |
| 104 | TROJAN DEBT SVC | 8,605 | 7,888 | 0 | |
| 105 | CONSERVATION DEBT SVC | 5,203 | 5,198 | 5,188 | |
| 106 | COWLITZ FALLS DEBT SVC | 11,619 | 11,583 | 11,571 | |
| 107 | WASCO DEBT SVC | 0 | 1,664 | 2,168 | |
| 108 | **Sub-Total** | **25,427** | **26,333** | **18,927** | |
| 109 | **Non-Federal Debt Service Sub-Total** | **520,782** | **570,197** | **554,006** | |
| 110 | | | | | |
| 111 | | | | | |
| 112 | **Total Operating Expenses** | **1,900,566** | **1,889,240** | **1,953,313** | |
| 113 | | | | | |
| 114 | **Other Expenses** | | | | |
| 115 | Depreciation (excl. TMS) | 118,058 | 121,829 | 124,594 | |
| 116 | Amortization (excludes ConAug amortization) | 55,567 | 60,241 | 65,172 | |
| 117 | Net Interest Expense | 163,080 | 173,193 | 182,940 | |
| 118 | LDD | 22,289 | 22,612 | 22,853 | |
| 119 | Irrigation Rate Mitigation Costs | 10,000 | 10,000 | 10,000 | |
| 120 | **Sub-Total** | 368,994 | 387,875 | 405,559 | |
| 121 | **Total Expenses** | **2,269,560** | **2,277,115** | **2,358,872** | |
| 122 | | | | | |
| 123 | **Revenue Credits** | | | | |
| 124 | Ancillary and Reserve Service Revs. Total | 73,131 | 61,970 | 62,715 | |
| 125 | Downstream Benefits and Pumping Power | 8,921 | 8,921 | 8,921 | |
| 126 | 4(h)(10)(c) | 84,707 | 84,927 | 84,676 | |
| 127 | Colville and Spokane Settlements | 4,600 | 4,600 | 4,600 | |
| 128 | FCCF | | | | |
| 129 | Energy Efficiency Revenues | 12,885 | 12,908 | 12,933 | |
| 130 | Miscellaneous | 3,420 | 3,420 | 3,420 | |
| 131 | **Total Revenue Credits** | **187,664** | **176,746** | **177,265** | |
| 132 | | | | | |
| 133 | **Augmentation Costs** | | | | |
| 134 | **IOU Reduction of Risk Discount (includes interest)** | 23,024 | 23,024 | 23,024 | |
| 135 | **Costs in this box are not subject to True-Up** | | | | |
| 136 | **Forecasted Gross Augmentation Costs** | | | | |
| 137 | Residual augmentation cost | 49,005 | | | |
| 138 | Other augmentation cost | 97,062 | 95,001 | 146,903 | |
| 139 | Minus revenues | 67,993 | 42,972 | 64,641 | |
| 140 | **Net Cost of Augmentation** | **101,098** | **75,053** | **105,286** | |
| 141 | | | | | |
| 142 | | | | | |
| 143 | **Minimum Required Net Revenue calculation** | | | | |
| 144 | Principal Payment of Fed Debt for Power | 202,331 | 172,483 | 185,065 | |
| 145 | Irrigation assistance | - | 2,950 | 6,590 | |
| 146 | Depreciation | 118,058 | 121,829 | 124,594 | |
| 147 | Amortization | 71,658 | 76,332 | 81,263 | |
| 148 | Capitalization Adjustment | (45,937) | (45,937) | (45,937) | |
| 149 | Bond Premium Amortization | 613 | 613 | 185 | |
| 150 | Principal Payment of Fed Debt exceeds non cash expenses | 57,939 | 22,596 | 31,550 | |
| 151 | Minimum Required Net Revenues | **57,939** | **22,596** | **31,550** | |
| 152 | | | | | |
| 153 | SLICE TRUE-UP ADJUSTMENT CALCULATION | | | | **3-Year Total Slice Rev. Reqt.** |
| 154 | Annual Slice Revenue Requirement (Amounts for each FY) | **2,240,934** | **2,198,018** | **2,318,443** | $ 6,757,395 |
| 155 | TRUE UP AMOUNT (Diff. between actuals and forecast) | | | | |
| 156 | AMOUNT BILLED (22.6278 percent) | | | | |
| 157 | Slice Implementation Expenses (not incl. in base rate) | **2,400** | **2,400** | **2,400** | |
| 158 | TRUE UP ADJUSTMENT | | | | |
| 159 | Annual Slice Revenue Requirement (Average) | **2,252,465** | | | |
| 160 | | | | | |
| 161 | **SLICE RATE CALCULATION ($)** | | | | |
| 162 | **Monthly Slice Revenue Requirement (3-Year total divided by 36 months)** | | | | **$ 187,705,407** |
| 163 | **One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Revenue Requirement divided by 100)** | | | | **$ 1,877,054** |
| 164 | | | | | |
| 165 | **ANNUAL BASE SLICE REVENUES** | | | | **$ 509,683,249** |
| 166 | **Annual Slice Implementation Expenses** | | | | **$ 2,400,000** |
| 167 | **TOTAL ANNUAL SLICE REVENUES** | | | | **$ 512,083,249** |

### 9.4 Rate Design Step Adjustments

Rate design adjustments are performed sequentially in the order described in the following section.

#### 9.4.1 Secondary and Other Revenue

Secondary and Other Revenue recognizes that BPA collects revenues from certain classes of service to which costs are not allocated and then credits these revenues to classes of service served with firm power. Projected secondary energy sales are the largest source of revenue credits.

##### 9.4.1.1 Secondary Energy Sales

On a resource planning basis and with system augmentation, BPA forecasts sufficient firm resources available to meet firm load obligations under critical water conditions. However, rates are set assuming that better than critical water conditions will occur. For this FY 2007-08 Lookback analysis, the secondary energy sales are assumed to be the same as in the WP-07 Final Proposal. BPA projects, secondary energy sales and revenues using 50 historical water-years as determined in RiskMod. *See* Conger, *et al.,* WP-02-E-BPA-14. The projected secondary energy revenue credits are allocated to firm loads so that BPA does not recover more than its revenue requirement.

The RiskMod model is used to project the level of secondary energy sales and revenues. BPA expects to sell secondary energy that will produce $1.749 billion in revenues over the three-year test period. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.5.3 (RDS 11).

##### 9.4.1.2 Other Revenue Credits

BPA sells firm power under FBS contract obligations and in the open market under the FPS rate schedule. For this FY 2007-2008 Lookback analysis, the other revenue credits are assumed to be the same as in the WP-07 Final Proposal. For FY 2007-2009, the forecast revenue from these sales is $555.7 million. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.5.3 (RDS 11).

#### 9.4.1.3 Allocation of Secondary Revenue Credits

Secondary Revenue credits are functionalized to generation and classified to energy. They are then allocated to loads served with Federal system resources (FBS and new resources). The generation-related revenues are allocated in this manner because they are associated with the use of Federal system resources to serve the firm contract sales and the secondary energy service. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.5.3 (RDS 11).

### 9.4.2 Firm Power Revenue Deficiencies Adjustment

BPA sells firm power at contractual rates and in the open market under the FPS rate schedule. Sales of such firm power are not necessarily made at the fully allocated costs of the power. Therefore, either a revenue surplus or a revenue deficiency will result when a comparison is made between the costs allocated to the firm power and the revenues received from the sale of such power. BPA has determined that in the FY 2007-2009 rate period, it will receive $342.7 million in revenues from the sale of firm power in various PNW and Southwest markets. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.5.4 (RDS 17). BPA has allocated $1.879 billion in generation costs to the firm power sold. BPA has allocated no revenue credits to the firm power sold. Therefore, there is a revenue deficiency of $1.536 billion over the three-year test period. This revenue deficiency is charged to all firm power (PF, IP, NR) customers. *See* Lookback Documentation, WP-07-E-BPA-44A, Tables 9.2.5.4 (RDS 17) and Table 9.2.5.5 (RDS 19).

Before the inter-rate-pool rate adjustments are made, an initial allocation to rate pools summary that includes: the COSA results, the allocation of secondary and other revenue credits, the allocation of FPS contract and FBS obligation contract revenue deficiencies is conducted. In addition, to recognize that BPA's Low Density Discount (LDD) and Irrigation Rate Mitigation Product (IRMP) will lower the revenues collected through PF Preference rate sales, an estimate of the lost revenue is added to the costs allocated to the PF rate pool. This initial allocation of costs to the individual rate pools is the starting position for the ensuing rate adjustments. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.5.5 (RDS 19).

**9.4.3 7(c)(2) Adjustment**

DSI rates are based on sections 7(c)(1), 7(c)(2), and 7(c)(3) of the Northwest Power Act. Section 7(c)(1)(B) provides that after July 1, 1985, the DSI rates will be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." Pursuant to section 7(c)(2), the DSI rates are to be based on BPA's "applicable wholesale rates" to its preference customers plus the "typical margins" included by those customers in their retail industrial rates. Section 7(c)(3) provides that the DSI rates are also to be adjusted to account for the value of power system reserves provided through contractual rights that allow BPA to restrict portions of the DSI load. This adjustment is typically made through a Value of Reserves (VOR) credit. To more accurately reflect the product Power Services may purchase from the DSI customers, the name has been changed to Supplemental Contingency Reserve Adjustment (SCRA). However, for this rate case, BPA is not proposing a uniform SCRA credit to be applied against DSI rates. Please refer to Final WPRDS, WP-07-FS-BPA-05, Appendix B. Thus, the DSI rates are set equal to the applicable wholesale rate, plus the typical margin, subject to the DSI floor rate test and the outcome of the section 7(b)(2) rate test. *See* Sections 9.3.3.4. and 9.3.3.5.

The applicable wholesale rate is the PF rate (in combination with the NR rate if new NLSLs were projected for the test period) at the DSI load factor. The typical margin is based generally on certain overhead costs that preference customers add to BPA's price of power in setting their retail industrial rates. The methods and calculations used to determine the typical margin are discussed in detail in the Final WPRDS, WP-07-FS-BPA-05, Appendix A. The net margin is 0.573 mills/kWh and has not been changed from the original WP-07 Final Proposal. As previously stated, a zero SCRA credit is being forecast in this rate case. This net margin is added to the seasonal and diurnal PF Energy rates. These adjusted PF Energy rates and the rate for demand are applied to the DSI test period billing determinants to determine the preliminary IP rate.

The section 7(c)(2) adjustment is necessary to account for the difference between the revenues BPA expects to recover from the DSIs at the initial IP rate and the costs allocated to the DSIs. This difference, known as the 7(c)(2) delta, is allocated to non-DSI customers, primarily the PF customers. Because the allocation of the 7(c)(2) delta changes the PF rate upon which the IP rate is based, the entire process is repeated with the revised PF rate from the previous iteration until the size of the 7(c)(2) delta does not change when a successive iteration is performed. This process has been reduced to an algebraic solution. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.5.6 (RDS 21).

BPA did not sell power under the IP rate schedule for this Lookback period. Therefore, the size of the 7(c)(2) delta for the Lookback period is inconsequential for ratemaking purposes. However, the calculation is shown for continuity of methodology purposes.

### 9.4.4 7(b)(2) Adjustment

The rate test specified in section 7(b)(2) of the Northwest Power Act ensures that BPA's public body, cooperative, and Federal agency customers' firm power rates applied to their requirements loads are no higher than rates calculated using specific assumptions that remove certain effects of the Northwest Power Act. If the section 7(b)(2) rate test triggers, the public body, cooperative, and Federal agency customers are entitled to rate protection. The cost of this rate protection is borne by other purchasers of firm power. In order to make these cost adjustments, the PF rate is bifurcated. The two resulting rates are the PF Preference rate, which receives the rate protection, and PF Exchange rate, which pays, at least in part, the cost of the rate protection.

The Lookback Section 7(b)(2) Rate Test Study, Section 10, indicates the section 7(b)(2) rate test has triggered and the PF rate applicable to BPA's preference customers should be adjusted downward. The amount of downward adjustment needed is implemented through a reduction of the PF Preference rate. Historically, it is at this point in the ratemaking process that BPA makes three adjustments in the rate design sequence to provide this protection to its preference customers and allocate the costs of the rate protection.

First, the PF Preference customer class is given a credit, which reduces its rate by the amount of the protection indicated in the section 7(b)(2) rate test. The 3.5 mills/kWh rate test trigger results in a protection amount of $643.1 million to PF Preference customers. The cost of providing this protection is allocated to the remaining firm power customers (PF Exchange, IP, and NR). *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.5.9 (RDS 30).

The second adjustment is the 7(b)(2) Industrial Adjustment. The amount of this adjustment is the value of a recalculated 7(c)(2) delta at the lower PF Preference rate. Because there is no IP load forecast for this rate period, the amount of the new 7(c)(2) delta is zero. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.5.10 (RDS 33).

In this Lookback analysis, there was no exchanging utility in deemer status. If there had been, a third adjustment would have been necessary to allocate an increase in the gross REP costs resulting from the bifurcation of the PF rate, causing the PF Exchange rate to be higher than the average combined rate before the bifurcation. This process is explained in the Supplemental WPRDS, WP-07-E-BPA-49, Section 3.3.6.

### 9.4.5 DSI Floor Rate Test

Section 7(c)(2) of the Northwest Power Act requires that the DSI rates in the post-1985 period "shall in no event be less than the rates in effect for the contract year ending June 30, 1985." Accordingly, a floor rate test is performed to determine if the proposed IP rate has been set at a level below the 1985 IP rate (the floor rate). If so, an adjustment is made that raises the IP rate to the floor rate and credits other customers with the increased revenue from the DSIs. If the proposed IP rate has been set at a level above the floor rate, no floor rate adjustment is necessary. Because the Lookback IP rate revenues are greater than the floor rate revenues, no adjustment was necessary to the IP rate. *See* Lookback Documentation, WP-07-E-BPA-44A, Tables 9.2.5.7and 9.2.5.8. With no DSI floor adjustment required, the final Rate Design Step allocations are shown in the Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.5.10 (RDS 33).

### 9.4.6 Slice Cost Calculation

Slice customers assume the obligation to pay a percentage of BPA's costs, rather than pay a set rate per kilowatt or kilowatthour. The Slice customer's obligation to pay is equal to the percentage of the FCRPS that the Slice customer elects to purchase. The costs considered by the Slice contract are referred to collectively as the Slice Revenue Requirement. The Slice Revenue Requirement is comprised of all of the line items in BPA's Power function revenue requirement identified in this rate case with certain limited exceptions. For the calculation of the cost of the Slice product in dollars per month for each percent of the Federal system, *see* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.13 (Slice Cost).

### 9.4.7 Slice PF Product Separation Step

In the COSA and Rate Design steps, costs were allocated to the various rate pools, including the PF Preference class of service that contained all firm PF Preference load. The Slice Separation Step separates out the PF Slice product revenues, firm loads, and revenue credits from the overall PF Preference rate pool, leaving the costs that must be covered by the remaining non-Slice PF Preference load through posted PF Preference energy, demand, and load variance charges. *See* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.6 (SLICESEP 01).

## 9.5 Rate Analysis Results

In this FY 2007-08 Lookback portion of the Supplemental Proposal, BPA is recalculating the FY 2007-2008 PF Exchange rate using the costs of a traditional REP in place of the costs of the REP settlements. The rate modeling described above resulted in an average PF Preference rate of 25.17 mills/kWh and a PF Exchange rate of 41.33 mills/kWh. This PF Exchange rate, when applied to the backcast ASCs, produced net REP benefits averaging $239 million per year for FY 2007 and FY 2008. *See* Table 14.2 in this Study and Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.7, Table 9.2.8, and Table 9.2.9.

# 10. SECTION 7(b)(2) RATE TEST STUDY, FY 2007-2008

## 10.1 Introduction

This section addresses the section 7(b)(2) rate test for FY 2007-2008 Lookback analysis. Recalculations of the section 7(b)(2) rate tests are necessary to determine a base PF Exchange rates to be used in the Lookback Analysis. There are two phases of the 7(b)(2) rate test for the Lookback analysis, the FY 2002-2006 rate test and FY 2007-2009 rate test. The first rate test is discussed in Section 6. The second rate test was conducted using the data available from the WP-07 Final Proposal, with assumption changes made to reflect changed conditions due to removal of the REP settlements. Because FY 2007-2008 are within the FY 2007-2009 rate period covered by the WP-07 Final Proposal, all 7(b)(2) rate calculations in this Lookback analysis were conducted using all three years of the rate period and the ensuing four years, FY 2007-2013.

Much of the discussion of the section 7(b)(2) rate test that is presented in Section 6 is applicable to this section as well. Therefore, this Section 10 is limited to a discussion of the differences between Section 6 and this section of the Lookback Study.

The Lookback Documentation, WP-07-E-BPA-44A, Section 10, contains the documentation of the Excel models and data used to perform the 7(b)(2) rate test. The output of these spreadsheet models is also in the Lookback Documentation, WP-07-E-BPA-44A, Section 10.

### 10.1.1 Purpose and Organization of Study

This section of the Lookback Study is organized in the same manner as Section 6, but as applied to FY 2007-2008. Because this Study only discusses differences from Section 6, there are no further direct references to tables in Section 10 of the Lookback Documentation

(WP-07-E-BPA-44A). However, Section 10 of the Lookback Documentation contains all of the appropriate tables that would otherwise be referenced in this Study.

#### 10.1.2 Basis of Study

##### 10.1.2.1 Implementation Methodology

###### 10.1.2.1.1 Implementation Methodology: Reserve Benefits

The financial consultant was Public Financial Management.

###### 10.1.2.1.2 Implementation Methodology: Rate Modeling

The three spreadsheet models have now been combined into one, RAM2007.

RAM2007 calculates annual Program Case rates for this FY 2007-2008 Lookback analysis for the years FY 2007-2009 and the following four years FY 2010-2013. Except for the treatment of Mid-Columbia resources and obsolete conservation resources, which have been removed from the resource stack, the ratemaking methodology of calculating rates for the Program Case of the rate test are identical to those used in calculating the rates in the WP-07 Final Proposal. Data changes between the WP-07 Final Proposal and the FY 2007-2008 Lookback have been limited to different IOU ASCs and exchange load forecasts.

### 10.2 Methodology

###### 10.2.1.1.1 Rate Design

The net margin is 0.573 mills/kWh in nominal dollars.

###### 10.2.1.1.2 Sales

For the FY 2007-2013 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.

#### 10.2.1.1.3 Financing Benefits

The financial advisor's analysis is included in the Final Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06, Appendix A . 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 (5.24 percent versus 5.42 percent). The financing benefit of BPA backing for conservation resources in the Program Case would be 17 and 16 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.

## 10.3 Summary of Results

Results for the two cases are summarized in Tables 10.1 and 10.2 below.

### 10.3.1 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 in Section 9. Table 10.1 below shows the projection of undiscounted nominal Program Case rates.

### 10.3.2 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 resources from the 7(b)(2)(D) stack. 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 10.2 below shows the projection of undiscounted nominal 7(b)(2) Case rates.

**10.3.3 The 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 the WP-07 Final Proposal rate test are comprised of BPA's acquired and projected conservation and billing credits, energy efficiency costs, and CRC 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 10.3 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 10.4). As shown in Table 10.4, the rate test triggers by 3.5 mills/kWh. Therefore, a rate adjustment, valued at about $214 million per year, is required.

**TABLE 10.1**
**PROGRAM CASE RATES**
(nominal mills/kWh)

| Fiscal Year | Rate | Applicable 7(g) Costs | Net Rate |
|---|---|---|---|
| 2007 | 30.11 | 1.74 | 28.37 |
| 2008 | 30.23 | 1.72 | 28.51 |
| 2009 | 32.15 | 1.77 | 30.38 |
| 2010 | 31.79 | 1.81 | 29.98 |
| 2011 | 33.48 | 1.78 | 31.70 |
| 2012 | 33.28 | 1.73 | 31.55 |
| 2013 | 34.94 | 1.76 | 33.18 |

**TABLE 10.2**
**7(b)(2) CASE RATES**
(nominal mills/kWh)

| Fiscal Year | 7(b)(2) Rate |
|---|---|
| 2007 | 31.68 |
| 2008 | 22.66 |
| 2009 | 23.79 |
| 2010 | 25.11 |
| 2011 | 25.70 |
| 2012 | 24.31 |
| 2013 | 26.02 |

**TABLE 10.3**
**DISCOUNT FACTORS FOR THE RATE TEST**

| Fiscal Year | Annual BPA Borrowing Rate | Cumulative Discount Factor |
|---|---|---|
| 2007 | .0667 | .9375 |
| 2008 | .0698 | .8763 |
| 2009 | .0722 | .8173 |
| 2010 | .0752 | .7601 |
| 2011 | .0759 | .7065 |
| 2012 | .0757 | .6568 |
| 2013 | .0755 | .6107 |

**TABLE 10.4**
**COMPARISON OF RATES FOR TEST**
(2002 mills/kWh)

| Fiscal Year | Discounted Program Case Rate | Discounted 7(b)(2) Case Rate |
|---|---|---|
| 2007 | 26.60 | 29.70 |
| 2008 | 24.98 | 19.86 |
| 2009 | 24.83 | 19.45 |
| 2010 | 22.79 | 19.09 |
| 2011 | 22.40 | 18.16 |
| 2012 | 20.72 | 15.96 |
| 2013 | 20.26 | 15.89 |
| Average Rate | 23.2 | 19.7 |
| Difference of Average Rates | 3.5 | |

# 11. BACKCAST OF IOU ASCs, FY 2007-2008

## 11.1 FY 2007 -2008 Backcast Overview

The purpose of this section is to estimate the annual ASC determinations that would have been made had the investor-owned utilities (IOUs) submitted ASC filings with BPA for 2007-2008. The backcast ASC determinations described in this section generally follows the same construct described in Section 7 for FY 2002-2006.

During FY 2007, no ASC filings were made with BPA and no filings are expected during 2008 for the purpose of establishing an ASC for 2008. Such filings would have been made under an active REP had BPA and the IOUs not executed REP Settlement Agreements. Consequently, BPA must estimate annual ASCs in order to determine what REP payments the IOUs would have received for this period under an active REP. This section of the Lookback Study will describe how these ASC determinations were made and present the results. BPA calculated annual ASCs for Avista, Idaho Power, NorthWestern Energy, PacifiCorp, Portland General Electric, and Puget Sound Energy. Public utilities were not included in this review process for FY 2007-2008.

To estimate these ASCs, BPA completed a detailed financial cost review of each IOU for 2006 and escalated the 2006 costs and loads to 2007 and 2008. The results of this cost review establish an annual "backcast" ASC determination for each utility. This section will focus on the backcast determination for FY 2007-2008 only. *See also* Section 7 of this Study.

## 11.2 Backcast ASC Determination Process

As described in Section 7, "backcast" is BPA's term for ASCs that BPA believes would have been determined had the REP been operational during the WP-07 rate period. A backcast ASC is based on review and analysis of 2006 FERC Form 1 data. These data were entered into the updated 1984 ASC Cookbook model, as described in Section 7, to establish estimates of the ASCs for each of the IOUs for the WP-07 rate period.

BPA applied the 1984 ASCM to all utilities, with exception of not using the jurisdictional approach as the source for data, *i.e.*, data used before a regulatory commission for ratesetting purposes. Instead, cost, revenue, and load data were obtained from FERC's Uniform System of Accounts (Form No. 1 filings) for each IOU. The FERC Form 1 data populated BPA's ASC Cookbook, an Excel-based computer modeling tool. Once populated with a utility's financial data, the ASC Cookbook separates, or "functionalizes," the total costs and revenues into the production, transmission, and distribution functions, *i.e.*, to functions that may be exchanged (exchangeable costs) and to those that may not be exchanged.

A two-step process was used to estimate the backcast ASCs for 2007 and 2008. First, a "base year" ASC was calculated using the 2006 FERC Form 1 data for each of the IOUs. This base year ASC includes all the changes discussed in Section 7. Second, the ASC Forecast Model was used to escalate the 2006 base year to estimate ASCs for each IOU for 2007 and 2008.

The model is designed to forecast the costs the utility will incur to meet load growth. It forecasts purchased power, sales for resale, fuel cost and non-fuel/purchase costs (NFPC). The ASC Forecast Model uses inflation escalators, gas price forecasts, and electric market price forecasts to escalate base ASC costs. In addition, the ASC Forecast Model estimates the cost of serving forecast load growth.

### 11.3 2006 Base Year ASC

To establish the base year ASC, the 2006 backcast ASC was used, as described in Section 7. Table 11.1 below shows the 2006 base year ASCs and exchange load.

**TABLE 11.1**
**2006 Base Year ASCs**

| | ASC ($/MWh) | Exch. Load (MWh) |
|---|---|---|
| Avista | 44.47 | 3,756,579 |
| Idaho Power | 28.36 | 7,038,389 |
| NorthWestern Energy | 52.62 | 898,218 |
| PacifiCorp (regional) | 40.91 | 9,251,568 |
| PacifiCorp (Oreg.) | 41.19 | 6,080,289 |
| PacifiCorp (Wash.) | 38.87 | 1,838,386 |
| PacifiCorp (Idaho) | 38.59 | 1,332,893 |
| Portland General | 49.72 | 8,049,271 |
| Puget Sound | 55.76 | 11,674,554 |

## 11.4 Contract System Load and Exchange Load

Contract System Load is the total consumer end-use load of a utility plus 5 percent distribution losses. *See* Section 7.4.4. BPA-generated load forecasts for 2007 and 2008 were used for Contract System Load and exchange loads. The Contract System Load forecasts are shown in Table 11.2; Table 11.3 shows the exchange load forecasts.

**Table 11.2**
**Forecast Contract System Loads**
(gigawatthours)

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|
| Avista | 9,226 | 9,392 | 9,572 | 9,779 | 9,984 | 10,184 | 10,360 | 10,472 |
| Idaho Power | 14,636 | 15,010 | 15,348 | 15,684 | 16,027 | 16,395 | 16,699 | 16,842 |
| NorthWestern | 7,370 | 7,432 | 7,517 | 7,548 | 7,617 | 7,681 | 7,769 | 7,809 |
| PacifiCorp | 22,480 | 22,714 | 22,923 | 23,119 | 23,326 | 23,527 | 23,964 | 24,269 |
| PacifiCorp-OR | 14,608 | 14,608 | 14,742 | 14,869 | 15,002 | 15,131 | 15,412 | 15,608 |
| PacifiCorp-WA | 4,374 | 4,519 | 4,561 | 4,600 | 4,640 | 4,681 | 4,768 | 4,828 |
| PacifiCorp-ID | 3,498 | 3,587 | 3,620 | 3,651 | 3,684 | 3,715 | 3,784 | 3,832 |
| Portland General | 19,354 | 20,404 | 20,629 | 20,855 | 21,082 | 21,302 | 21,638 | 21,838 |
| Puget Sound | 22,146 | 22,283 | 22,563 | 22,872 | 23,171 | 23,457 | 23,669 | 23,876 |

**Table 11.3**
**Forecast Exchange Loads**
(gigawatthours)

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|
| Avista | 3,757 | 3,824 | 3,897 | 3,981 | 4,065 | 4,147 | 4,218 | 4,264 |
| Idaho Power | 7,038 | 7,218 | 7,390 | 7,543 | 7,707 | 7,884 | 8,030 | 8,099 |
| NorthWestern | 898 | 951 | 962 | 966 | 975 | 983 | 994 | 999 |
| PacifiCorp | 9,252 | 9,287 | 9,372 | 9,453 | 9,537 | 9,619 | 9,798 | 9,923 |
| PacifiCorp-OR | 6,080 | 6,054 | 6,110 | 6,163 | 6,218 | 6,270 | 6,388 | 6,469 |
| PacifiCorp-WA | 1,838 | 1,879 | 1,896 | 1,913 | 1,930 | 1,946 | 1,982 | 2,008 |
| PacifiCorp-ID | 1,333 | 1,353 | 1,366 | 1,378 | 1,390 | 1,402 | 1,428 | 1,446 |
| Portland General | 8,049 | 8,286 | 8,378 | 8,470 | 8,562 | 8,651 | 8,788 | 8,869 |
| Puget Sound | 11,675 | 11,747 | 11,894 | 12,057 | 12,215 | 12,365 | 12,477 | 12,586 |

## 11.5 Forecast Contract System Costs

Contract System Costs include NFPC, fuel costs, purchased power, and sales for resale. The NFPC escalate 2006 base year costs by inflation. 2006 base year fuel costs are escalated either by natural gas or, for coal, by 0.5 percent. Table 11.4 shows the escalation rates used in the ASC Forecast Model. Purchased power and sales for resale are forecast as described below.

**Table 11.4**
**Inflation Rates and Price Forecasts**

| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|
| Inflation Rates | 1.91% | 2.06% | 2.09% | 2.30% | 2.48% | 2.39% | 2.35% |
| Electricity Price Forecast | 58.46 | 50.87 | 50.68 | 51.95 | 53.25 | 54.58 | 55.94 |
| Gas Price Forecast | 6.56 | 6.37 | 6.18 | 5.77 | 5.51 | 5.77 | 6.09 |

### 11.5.1 Forecast Purchased Power

Forecasts of a utility's purchased power costs are a function of historical purchases and growth of the utility's total retail load. The ASC Forecast Model adds increases in total retail load to the utility's purchased power, priced at market prices.

In the FERC Form 1, utilities separate purchased power by the type and length of the purchase and also report any adjustments. The ASC Forecast Model distinguishes between long-term and short-term purchased power. The FERC Form 1 reports the following categories of purchased power:

Requirements service (RQ) – service that the supplier plans to provide on an ongoing basis (*i.e.*, the supplier includes project load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers;

Long-term firm service (LF) – service for five years or longer, cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (*e.g.*, the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service.)

intermediate-term firm service (IF) – the same as LF service expect that "intermediate-term" means longer than one year but less than five years.

long-term service from a designated generating unit (LU) – LF service where the availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit;

intermediate-term service from a designated generating unit (IU) – the same as LU service expect that intermediate-term" means longer than one year but less than five years;

short-term service (SF) – all services where the duration of each period of commitment for service is one year or less;

other services (OS) – services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the length of the contract and service from designated units of less than one year;

exchanges of electricity (EX) – transactions involving a balancing of debits and credits for energy, capacity, *etc.*, and any settlements for imbalanced exchanges;

not applicable (NA) – PacifiCorp used NA for not applicable: adjustment for inadvertent interchange; and out of period adjustments (AD) – accounting adjustments or true-ups for service provided in prior reporting years.

Long term purchases include the RQ, LF, LU, IF and IU categories. It was assumed that long term purchases are constant over the forecast period; the forecast for long-term purchased power costs is the base year purchases escalated at the rate of inflation.

Short-term purchases include the OS, SF, AD, NA, and EX categories. The quantity of short-term purchases in the 2006 base year ASC is normalized to equal the average of short-term purchases from 2002-2006 for Avista, Idaho Power, Portland General and Puget Sound. PacifiCorp's historical quantity of short-term purchases for the 2002-2003 differed substantially from the 2004-2006 purchases. Therefore, the quantity of PacifiCorp short-term purchases was averaged over 2004-2006. NorthWestern's quantity of short-term purchases for the years prior to 2006 was so significantly different from 2006 that the forecast uses the 2006 short-term purchases only.

The averaged short-term purchases are priced at the utility's 2006 average purchase price. The forecast then holds the quantity of short-term wholesale purchases constant through the forecast period and prices them at BPA's forecast market price of electricity for the years 2007-2013.

The forecast is based on the assumption that the utility is in resource balance. Therefore, annual increases in a utility's total retail load are assumed to be served through market purchases at BPA's annual forecast market price of electricity.

### 11.5.2 Sales for Resale Revenue Credit

In the FERC Form 1, utilities separate sales for resale by the type and length of the sale and also report any adjustments. The ASC Forecast Model distinguishes between long-term and short-term sales for resale. The FERC Form 1 reports the same categories for sales for resale as for purchased power.

The ASC forecast assumed that the quantity of long term and intermediate term firm sales are constant for 2007-2013 and that sales revenue escalates at the rate of inflation. The quantity of short-term sales in the 2006 base year ASC is normalized to equal the average of short-term sales from 2002-2006 for Avista, Idaho Power, Portland General and Puget Sound. PacifiCorp's historical quantity of short-term sales for the 2002-2003 differ substantially from the 2004-2006 purchases. Therefore, the quantity of PacifiCorp short-term sales was averaged over 2004-2006. NorthWestern's quantity of short-term sales for the years prior to 2006 was so significantly different from 2006 that the forecast uses the 2006 short-term sales only.

The averaged short-term sales are priced at the utility 2006 average sales price. The forecast then holds the quantity of short-term wholesale sales constant through the forecast period and prices them at BPA's forecast market price of electricity for the years 2007-2013.

## 11.6 Contract System Costs

The ASC Forecast Model calculates Contract System Costs as follows:

$$\begin{aligned}\text{Exchange Cost}_{2007} = {} & \Sigma \text{ Rate Base Accounts} \times (1+ \text{escalator}_{(\text{by account})}) \times \text{ROR} \\ & + \Sigma \text{ Rate Base Accounts} \times (1+ \text{escalator}_{(\text{by account})})) \times \text{Federal Income Tax Factor} \\ & + \Sigma \text{ Expense Accounts}_{(\text{by account})}) \times (1+ \text{escalator}_{(\text{by account})})) \\ & + \text{Wholesale Purchase Expense}_{2007} \\ & - \text{Wholesale Sales for Resale Revenue Credit}_{2007} \\ & + \text{Cost of Load Growth}\end{aligned}$$

## 11.7 2007 – 2008 Backcast ASCs

The ASC backcasts are calculated by dividing the Contract System Costs by Contract System Load. The 2007-2008 backcast ASCs are shown in Table 11.5. The detailed ASC Forecast Model for each of the IOUs is provided in the Lookback Documentation, WP-07-E-BPA-44A.

**TABLE 11.5**
**2007 and 2008 Backcast ASC Determinations**

| | 2007 | | 2008 | |
|---|---|---|---|---|
| | ASC ($/MWh) | Exch. Load (MWh) | ASC ($/MWh) | Exch. Load (MWh) |
| Avista | 48.28 | 3,824,029 | 49.80 | 3,897,357 |
| Idaho Power | 32.44 | 7,218,346 | 32.98 | 7,380,466 |
| NorthWestern | 51.03 | 974,699 | 51.98 | 982,688 |
| PacifiCorp | 40.11 | 9,286,925 | 41.08 | 9,372,307 |
| PacifiCorp-OR | 40.75 | 6,054,400 | 41.73 | 6,110,062 |
| PacifiCorp-WA | 37.18 | 1,879,097 | 38.03 | 1,869,372 |
| PacifiCorp-ID | 37.24 | 1,353,429 | 38.11 | 1,365,872 |
| Portland General | 49.04 | 8,469,639 | 47.49 | 8,377,545 |
| Puget Sound | 53.66 | 11,746,838 | 52.69 | 11,894,349 |

# PART THREE:  LOOKBACK RESULTS

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# 12. PART THREE – 2002-2008 LOOKBACK

## 12.1 Lookback Results Introduction

Part Three of the Lookback Study presents BPA's proposal to use the results of Part One and Part Two to compute Lookback Amounts. It further presents BPA's proposal on the return of the Lookback Amounts to preference customers.

The Lookback Amount for each IOU is the difference between the amounts paid pursuant to the REP Settlement Agreements and the amount the IOU would have received if it had signed a RPSA and participated in the REP.

Section 13 sets forth the annual amounts that each IOU received pursuant to its REP Settlement Agreement, including any amounts paid pursuant to an LRA.

Section 14 sets forth the annual amounts that each IOU would have received pursuant to an RPSA using the ASCs and PF Exchange rates developed in Parts One and Two.

Section 15 combines the results of Section 13 with the results of Section 14 to compute the Lookback Amount for each IOU, subject to certain provisions regarding deemer balances and LRA payments. Section 15 then discusses BPA's proposed methods of recapturing the Lookback Amounts from the IOUs and returning the amounts to preference customers.

## 13. ACTUAL AND PROJECTED SETTLEMENT BENEFITS PAID TO IOUs FOR FY 2002-2008

### 13.1 Actual Settlement Benefits Paid to the IOUs

BPA paid $2,130,099,581 in REP settlement benefits to the IOUs from November 2001 (for October 2001) through April 30, 2007 (March 2007 payment was paid in April 2007). The amounts of benefits paid to each IOU are summarized in Tables 13.1.1 through 13.1.7. *See* Lookback Documentation, WP-07-E-BPA-44A. Payments were made for FY 2002-2006 under the REP Settlement Agreements to all IOUs and under the LRAs to Puget Sound Energy and PacifiCorp. Payments made for FY 2007 were made under the 2004 Amendments to the REP Settlement Agreements, which also deferred the Reduction of Risk Discount portion of the LRAs. During the implementation of the REP Settlement Agreements and their Amendments, BPA conducted a Compliance Oversight Function to help ensure that the benefits that BPA paid the IOUs were actually paid to their residential and small farm customers. BPA prepared an annual accounting summary of the actual monthly BPA Power Bill components for each IOU. All cash payments, with the exception of the amounts paid for undertaking conservation efforts, and including the value of the sale of power to Portland General Electric Co., were included in this annual accounting. Adjustments were made until both BPA and the IOU agreed with the results, and each IOU confirmed the accuracy of BPA's accounting summary.

Annual certification statements were prepared by each IOU that summarized the beginning balance in the "balancing account," the amount of benefits received from BPA, the amount that was distributed to eligible residential and small farm customers, and the ending balance in the balancing account for the contract year. The contract year was the same as BPA's fiscal year.

The balancing account reflected the balance owed to residential and small farm consumers when the amount of credits distributed during the year was less than the amount of settlement benefits received for the year. The balancing account reflects any advances made by the IOU when the amount of settlement benefits paid to residential and small farm consumers exceeded the amount of benefits received from BPA for the year.

In addition, the benefit payments were required to be placed in an interest-bearing account until they were paid to eligible consumers. Some IOUs and their state commissions also allowed interest earned to be retained by the IOU when the level of benefits paid to retail customers exceeded the amount of Settlement benefits received from BPA.

The annual certification statements accounts for the interest owed customers and the interest kept by the IOU, if applicable. The annual certification statements contained the following affirmation statement: "By signing this certification, I affirm that all the information provided in this statement is true and correct to the best of my knowledge and belief." The annual accounting/certification statements for settlement benefits were signed by officers/officials (generally the Chief Financial Officer) of the IOUs.

After the settlement payments were suspended in May 2007, BPA prepared additional accounting summaries of other settlement benefits as follows: (1) the benefits paid to the IOUs for Conservation and Renewable efforts; (2) settlement benefits that were deferred, subsequent repayment of a portion of those deferrals along with accrued interest and the amounts written-off by some IOUs, and the remaining balances owed PacifiCorp and Puget Sound Energy on their deferral balances; and (3) accountings that summarized the "reduction of risk" activity, balances after partial write-downs as of September 30, 2006, accrued interest, payments made during FY 2007, and the remaining balances owed PacifiCorp and Puget Sound Energy for the reduction of risk contract provisions. The accounting statements covering these additional settlement aspects were reviewed and certified by the IOUs and signed by an officer/official of the company subject to the above affirmation statement.

The summaries of benefits paid to the individual IOUs (Lookback Documentation, WP-07-E-BPA-44A, Tables 13.1.1-13.1.7) include the additional payment information calculated following the suspension of payments in May, 2007. These tables provide a complete and accurate accounting of the total settlement benefits paid to each IOU for FY 2002-2007.

**Table 13.1**
**REP Settlement Benefits – FY 2002-2006**
($000)

| | 2002 | 2003 | 2004 | 2005 | 2006 | Annual Average |
|---|---|---|---|---|---|---|
| Avista | 11,807 | 8,976 | 11,903 | 11,816 | 11,922 | 11,285 |
| Idaho Power | 14,567 | 12,041 | 15,927 | 15,800 | 15,949 | 14,857 |
| NorthWestern Energy | 3,105 | 2,376 | 3,161 | 3,135 | 3,168 | 2,989 |
| PacifiCorp | 117,064 | 109,402 | 121,318 | 120,986 | 120,981 | 117,950 |
| Portland General Electric | 59,011 | 43,620 | 62,456 | 87,646 | 128,305 | 76,208 |
| Puget Sound Energy | 172,779 | 150,916 | 179,103 | 178,614 | 178,614 | 172,005 |
| Total | 378,333 | 327,331 | 393,868 | 417,997 | 458,939 | 395,294 |

Note that total benefits paid the IOUs for the October 2006 through March 2007 period was $168.377 million.

## 13.2 Projected Settlement Benefits that Would Have Been Paid to the IOUs for the Remainder of FY 2007 and FY 2008

BPA also prepared a summary of the projected benefits that would have been paid to the IOUs for the remainder of FY 2007 and all of FY 2008. These summaries of projected benefits are contained in Tables 13.2.1 through 13.2.7. These projections are used to inform the calculation of Lookback Amounts as outlined in Section 15 of this Study.

**Table 13.2**
**REP Settlement Benefits – FY 2007-2008**
($000)

| | 2007 | 2008 | Annual Average |
|---|---|---|---|
| Avista | 10,561 | 21,005 | 21,044 |
| Idaho Power | 15,866 | 31,578 | 31,629 |
| NorthWestern Energy | 1,990 | 3,947 | 3,958 |
| PacifiCorp | 46,285 | 92,584 | 92,579 |
| Portland General Electric | 39,792 | 78,946 | 79,159 |
| Puget Sound Energy | 54,155 | 108,324 | 108,319 |
| Total | 168,649 | 336,385 | 336,689 |

# 14. RESIDENTIAL EXCHANGE BENEFITS UNDER THE TRADITIONAL RESIDENTIAL EXCHANGE PROGRAM

## 14.1 Constructing IOU REP Benefits

The Lookback analysis seeks to first answer two questions: (1) what PF Exchange rate levels would have been established for the sale of exchange power to the IOUs; and (2) what ASCs would have been established for the purchase of exchange power from the IOUs? Given the answer to those two questions, a more basic question can be answered, namely, what REP benefits would the IOUs have received in the absence of the REP settlements?

## 14.2 IOU REP Benefits for FY 2002-2006

The description of how BPA reconstructed the FY 2002-2006 PF Exchange rate for the sale of exchange power is presented in Sections 5.2 and 5.3 of this Study. The description of how BPA constructed the ASCs for the purchase of exchange power is presented in Section 5.1 of this Study. The analysis to determine the amount of REP benefits each IOU would have received during the Lookback period is discussed below. This part of the analysis does not address the issue of deemer account balances, which is addressed in Section 15.

Because BPA's actual revenues collected were sufficient to meet the costs of the FY 2002-2006 period, the level of actual revenues collected is the starting point of the analysis. The actual revenues collected for the rate period are then adjusted by: (1) subtracting the amount of REP Settlement Agreement Benefits paid as expressed in Section 13; (2) subtracting the net cost to BPA of furnishing power to IOUs, included in Section 13; and (3) adding the net REP benefits determined by using the recalculated base PF Exchange rate and the backcast utility ASCs and eligible exchangeable loads, as summarized below. These annual adjusted revenue amounts for each fiscal year are the "Annual Revenue Targets."

If the model projects that revenues from recalculated rates fall short of the Annual Revenue Targets for a year, then the base PF Preference and PF Exchange rates are increased by means of a CRAC percentage increase to both rates. The CRAC increases the revenue and, in turn, decreases the level of net REP benefits until the difference between the net revenues collected and the Annual Revenue Target is zero. The inverse is true if revenues over-collect the Annual Revenue Target. The level of Lookback REP benefits at a CRAC'd PF Exchange rate is solved in the model through an intrinsic goal-seeking function. This process is described more completely in Section 5.5 of this Study and in Brodie, *et al.,* WP-07-E-BPA-58. The forecasted Lookback benefits for FY 2002-2006 are outlined in Table 14.1, which is based on Post-Processor output, Documentation Table 5.3.6.

**Table 14.1**
**Lookback REP Benefits – FY 2002-2006**
($000)

| | 2002 | 2003 | 2004 | 2005 | 2006 | Annual Average |
|---|---|---|---|---|---|---|
| Avista | 14,897 | 8,812 | 25,853 | 12,586 | 15,721 | 15,574 |
| Idaho Power | 0 | 0 | 0 | 0 | 0 | 0 |
| NorthWestern Energy | 5,950 | 4,216 | 10,061 | 7,298 | 11,081 | 7,721 |
| PAC-Oregon | 0 | 0 | 17,125 | 22,100 | 5,489 | 8,937 |
| PAC-Washington | 0 | 0 | 0 | 0 | 0 | 0 |
| PAC-Idaho | 0 | 0 | 0 | 0 | 0 | 0 |
| Portland General Electric | 94,420 | 38,906 | 45,504 | 62,919 | 75,906 | 63,531 |
| Puget Sound Energy | 92,805 | 44,785 | 94,813 | 134,141 | 180,651 | 109,439 |
| TOTALS | 208,072 | 96,720 | 193,357 | 239,044 | 288,818 | 205,202 |

### 14.3 IOU REP Benefits for FY 2007-2008

The description of how BPA reconstructed the FY 2007-2008 PF Exchange rate for the sale of exchange power is presented in Sections 9.2 and 9.3 of this Study. The description of how BPA constructed the ASCs for the purchase of exchange power is presented in Section 9.1 of this

Study. Once these two pieces are constructed, the analysis to determine the amount of REP benefits each IOU would have received during the Lookback period can be conducted.

Section 9.5 instructs that the annual net IOU REP benefits for FY 2008 and FY 2009 average $239 million. *See also* Lookback Documentation, WP-07-E-BPA-44A, Table 9.2.7, Table 9.2.8, and Table 9.2.9. The results are summarized in Table 14.2.

**Table 14.2**
**Lookback REP Benefits – FY 2007-2008**
($000)

| | 2007 | 2008 | Annual Average |
|---|---|---|---|
| Avista | 26,594 | 33,008 | 29,801 |
| Idaho Power | 0 | 0 | 0 |
| NorthWestern Energy | 9,223 | 10,249 | 9,736 |
| PAC-Oregon | 0 | 2,507 | 1,254 |
| PAC-Washington | 0 | 1,573 | 786 |
| PAC-Idaho | 0 | 0 | 0 |
| Portland General Electric | 63,869 | 51,565 | 57,717 |
| Puget Sound Energy | 144,821 | 135,110 | 139,965 |
| Totals | 244,507 | 234,011 | 239,259 |

# 15. LOOKBACK AMOUNTS, RECOVERY AND DISPOSITION

## 15.1 Introduction

The purpose of this section of this study is to explain, in detail, how BPA arrives at the annual Lookback Amounts for each IOU and how it proposes to recover these amounts from the IOUs and distribute such recovered amounts to the COUs. In addition, it will describe how BPA proposes to establish and return amounts COUs overpaid in rates for FY 2007-2008 that are not included in Lookback Amounts. BPA's proposal is to: (1) determine the amount of overpayments to the IOUs for FY 2002-2008 period; (2) recover the overpayments, to the extent possible, from each IOU; and (3) return the overpayments to COUs.

The calculation of Lookback Amounts requires BPA to quantify the total payments to each IOU under the REP settlements, estimate the total amounts each IOU would have received under the REP in the absence of the REP Settlement Agreements, and to then calculate the appropriate differences.

Determining annual Lookback Amounts for each IOU is not a simple proposition. Several factors affect the calculations of the Lookback Amounts. These factors include treatment of the following:

(1) 2004 Amendments (to the REP Settlement Agreements) remanded to BPA;

(2) Reduction of Risk Discount remanded to BPA;

(3) Load Reduction Agreements;

(4) Deemer account balances certain utilities owe BPA;

(5) Monies collected in rates since May 2007 for REP settlement payments that have not been disbursed to the IOUs.

BPA's proposed treatment of these issues is described in detail in the following sections.

### 15.2 Determining the IOU Lookback Amounts for FY 2002-2008

To determine each IOU's annual and cumulative Lookback Amount, BPA created an Excel-spreadsheet model that takes certain inputs, such as the REP settlement benefits (computed as described in Section 13), the REP benefits (computed as described in Section 14), and deemer account balances (including accrued interest) as of the beginning of FY 2002. In addition, the model uses certain assumptions regarding inflation and interest rates applicable to FY 2002-2008 and post-FY 2009. *See* Table 15.1 for a list of model inputs. This model is hereinafter referred to as the Lookback/Lookforward Model (LBLF Model). Tables included in this Study have been extracted from this model, unless otherwise noted.

**Table 15.1**
**Inputs for LBLF Model**

1. Inputs to Model
   (a) Settlement and LRA Payments made to IOUs from FY 2002 through the first six months of FY 2007 (referred to as 2007A)
   (b) Settlement Payments that would have been made to IOUs for the last six months of FY 2007 (2007B) and for FY 2008
   (c) Recalculated REP Benefits for FY 2002-2008
   (d) FY 2002-2006 annual inflation rates used to adjust Nominal Lookback amounts to a certain year's current dollars (either 2006, 2007 or 2008);
   (e) Annual average interest rates used to accrue interest on outstanding IOU Deemer Account balances starting in FY 2002
   (f) Deemer Account balances for Avista, Idaho, and NorthWestern Energy, including accrued interest beginning in FY 2002 (PacifiCorp, Puget Sound and Portland General had no Deemer Accounts)
   (g) Whether deemer balances for each utility accrue simple or compound interest. By contract, Avista's deemer balance accrues simple interest; Idaho Power (Idaho) and NorthWestern Energy (NorthWestern) accrue compound interest
   (h) Prospective FY 2009 REP benefits for each IOU, which are then used in conjunction with assumed escalation of REP benefits to forecast REP benefits going forward to fiscal 2028

(i) Assumed escalation rate(s) for REP benefits

(j) Assumed annual average interest rate for years 2010 through 2028 (which is currently set at the daily twenty-year daily average T-bill rate for 2002 through fiscal 2007). This input is used to accrue interest on unpaid Lookback balances starting FY 2010

(k) Scenario Analysis Inputs

(1) Whether or not to adjust the Nominal Lookback Amounts for inflation to the input reference year's dollars

(2) The year through which to adjust the Nominal Lookback Amounts for inflation, which can be 2006, 2007 or 2008

(3) The amount of the Cap on aggregate IOU REP benefits. Each utility's share of this Cap is proportional to its share of the calculated FY 2009 REP Benefits

(4) A minimum percentage of REP benefits allowed each IOU until the computed Lookback Amounts have been amortized

2. Model switches that select scenario parameters

(a) Turn on/off the escalation of the 2002-2006 Lookback Amounts from nominal dollars into 2006, 2007 or 2008 dollars

(b) Turn on/off the workoff of Deemer Balances during the 2002-2008 time period

(c) Turn on/off each utility's REP benefit Cap (in 1.k.3 above) to determine the annual set off of its Lookback Amount balance; and turn on the use of the minimum REP benefits to be received

### 15.2.1 Treatment of Deemer Accounts

#### 15.2.1.1 Overview of Treatment of Deemer Amounts

BPA's 1981 RPSAs established what was called a "deemer account." In the event that an exchanging utility's ASC fell below the applicable PF Exchange rate, rather than pay BPA, the utility would accumulate a balance in a deemer account based on the difference between its ASC and the PF Exchange rate multiplied by the utility's eligible exchange load. The 1981 RPSA provided that any obligations incurred under that RPSA would continue until satisfied, even if the RPSA expired. The RPSA also provided that the utility must repay its deemer balance before receiving any positive REP benefits. Idaho Power, NorthWestern Energy, and Avista Corporation all had deemer balances as of October, 2000.

BPA proposes that its determination of the amount of REP benefits that would have been provided to an IOU in the absence of the REP Settlement Agreements must account for a utility's deemer balance. Specifically, BPA proposes that any REP benefits that an IOU with a deemer balance would have received will first be used to extinguish its deemer balance before being compared to the REP settlement benefits to establish a Lookback Amount for that IOU. Under BPA's proposal, annual REP benefits that NorthWestern Energy and Avista would have received for FY 2002-2007 must be applied first to their respective deemer balances until they are exhausted. Using this approach, NorthWestern extinguishes its deemer in FY 2005 and Avista in FY 2007. Idaho Power's deemer balance requires a different treatment described below.

**15.2.1.2 Calculation of Deemer Balances**

Deemer balances are calculated based on the terms and conditions of the 1981 RPSAs and subsequent agreements.

Avista's agreement stated that interest on deemer balances would not compound; therefore, interest is calculated only on the initial deemer balance (or remaining balance thereof) and not on the interest that has accrued. In applying REP benefits to Avista's deemer balances, benefits are first applied against the accumulated interest component of the total deemer balance. Once the interest component is zeroed out, remaining benefits apply against the principal component.

NorthWestern's (formerly Montana Power Company) agreement specified that interest would compound, so the determination of interest on the balances for Lookback purposes is done accordingly. When the agreement specifies compounding of interest, no distinction is needed between the initial deemer principal amount and the interest component.

Idaho Power's agreement specified that interest would compound.

The agreements specified the same rate of interest on deemer accounts for all companies. The interest rate is the Federal Reserve Board, H.15 Selected Interest Rates, bank prime loan rate. Interest rates are fixed for each quarter beginning October, January, April, and July. The rates are determined by averaging the prime rates (to hundredths of a percent) for the second, third and fourth months prior to each quarter. For example, the interest rate for the quarter beginning October 2007 would be set equal to the average of the prime rates for August, July, and June 2007.

Tables 15.2 and 15.3 show how REP benefits were applied to deemer balances for Avista and NorthWestern, respectively. Idaho Power's deemer balance is determined outside the LBLF Model using the same monthly calculation approach used to determine its deemer balance prior to October 1, 2001.

#### 15.2.1.3 Individual Utility Results

##### 15.2.1.3.1 Avista Deemer Treatment

Table 15.2 shows how the deemer balance was used to compute REP benefits for Avista. First, Avista's outstanding start-of-year deemer balance is stated on the first line of the table. Next, pre-deemer REP benefits (as discussed in Section 14 of this Study) is shown on the second line of the table. This amount is applied to the outstanding deemer balance until the deemer balance is reduced to zero.

Because Avista's agreement called for a simple interest computation, the pre-deemer REP benefits are applied first to the deemer interest balance and then, if there are any remaining benefits due, to the principal balance. Interest is then computed on the new principal balance, excluding any previously accrued interest. Interest accruals use a mid-year convention.

The result of the application of pre-deemer REP benefits and accrued interest is the end-of-year deemer balance. Once the deemer balance is paid to zero in FY 2007, Avista begins realizing REP benefits that can be used to offset REP settlement benefits. Table 15.2 is a summary of the results of the full calculation, shown in the Lookback Documentation, WP-07-E-BPA-44A, Table 15.1.

**Table 15.2**
**Avista Deemer Treatment**
(millions of dollars)

| | 2002 | 2003 | 2004 | 2005 | 2006 | 2007A | 2007B | 2008 | Total |
|---|---|---|---|---|---|---|---|---|---|
| SOY Deemer Balance | 85.58 | 72.85 | 65.79 | 41.52 | 30.64 | 16.46 | 3.53 | 0.00 | |
| REP Benefits | 14.90 | 8.81 | 25.85 | 12.59 | 15.72 | 13.30 | 13.30 | 33.01 | 137.47 |
| Applied to Deemer | 14.90 | 8.81 | 25.85 | 12.59 | 15.72 | 13.30 | 3.53 | 0.00 | 94.70 |
| Interest Accrued | 2.16 | 1.76 | 1.58 | 1.71 | 1.54 | 0.37 | 0.00 | 0.00 | 9.12 |
| EOY Deemer Balance | 72.85 | 65.79 | 41.52 | 30.64 | 16.46 | 3.53 | 0.00 | 0.00 | |
| REP Benefits Earned | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 9.76 | 33.01 | 42.77 |
| Interest Rate Applied | 5.49% | 4.47% | 4.02% | 5.01% | 7.01% | 8.21% | 8.25% | 8.25% | |

**15.2.1.3.2 NorthWestern Deemer Treatment**

Table 15.3 shows how the deemer balance was used to compute REP benefits for NorthWestern Energy. First, NorthWestern's outstanding start-of-year deemer balance is stated on the first line of the table. Next, pre-deemer REP benefits (as discussed in Section 14 of this Study) are shown on the second line of the table. This amount is applied to the outstanding deemer balance until the deemer balance is reduced to zero.

NorthWestern's agreement allowed compound interest. Therefore, the pre-deemer REP benefits can be applied to the total deemer balance. Interest is then computed on the new principal balance, using a mid-year convention. The result of the application of pre-deemer REP benefits and accrued interest is the end-of-year deemer balance. Once the deemer balance is paid to zero in FY 2005, NorthWestern begins realizing REP benefits that can be used to offset REP settlement benefits. Table 15.3 is a summary of the results of the full calculation, shown in the Lookback Documentation, WP-07-E-BPA-44A, Table 15.2.

**Table 15.3**
**NorthWestern Deemer Treatment**
(millions of dollars)

| | 2002 | 2003 | 2004 | 2005 | 2006 | 2007A | 2007B | 2008 | Total |
|---|---|---|---|---|---|---|---|---|---|
| SOY Deemer Balance | 19.52 | 14.48 | 10.81 | 0.98 | 0.00 | 0.00 | 0.00 | 0.00 | |
| REP Benefits | 5.95 | 4.22 | 10.06 | 7.30 | 11.08 | 4.61 | 4.61 | 10.25 | 58.08 |
| Applied to Deemer | 5.95 | 4.22 | 10.06 | 0.98 | 0.00 | 0.00 | 0.00 | 0.00 | 21.21 |
| Interest Accrued | 0.91 | 0.55 | 0.23 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.69 |
| EOY Deemer Balance | 14.48 | 10.81 | 0.98 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | |
| Benefits Earned | 0.00 | 0.00 | 0.00 | 6.31 | 11.08 | 4.61 | 4.61 | 10.25 | 36.87 |
| Interest Rate Applied | 5.49% | 4.47% | 4.02% | 5.01% | 7.01% | 8.21% | 8.25% | 8.25% | |

#### 15.2.1.3.3 Idaho Deemer Treatment

In calculating the Lookback Amount for Idaho Power, the results show Idaho Power did not qualify for REP benefits during FY 2002-2008 due to its low ASC. Therefore, it is assumed that Idaho Power would not have signed an RPSA in 2000 and that the only change to its deemer balance during FY 2002-2008 is the continuing accumulation of interest on the deemer balance. As a result, Idaho Power's Lookback Amount is equal to the REP settlement benefits it received. Idaho Power's deemer balance as of October 1, 2007, was $243.66 million.

### 15.2.2 Recalculated REP Benefits Limited to REP Settlement Payments

A second condition is proposed on the calculation of the amount to be recovered from each IOU for FY 2002-2008. For purposes of calculating the Lookback Amount for each utility, an IOU cannot receive more in REP benefits under an RPSA than it received, or would have received, under the REP settlements. This condition is applied on an annual basis.

### 15.2.3 Treatment of the Load Reduction Agreements

As described in Bliven, *et al.*, WP-07-E-BPA-52, the LRAs with PacifiCorp and Puget Sound Energy are contracts wherein BPA bought back power from the two IOUs during FY 2002-2006 to limit BPA's exposure to the high and volatile market prices of the West Coast energy crisis. Challenges to these Agreements were dismissed by the Ninth Circuit as untimely and moot.

This proposal treats these arrangements as enforceable agreements for purposes of calculating Lookback Amounts. Consequently, the Lookback analysis proposes the following treatment for the LRA payments. First, the LRA payments are included as part of the total calculation of REP settlement benefits paid to PacifiCorp and PSE. Next, PacifiCorp and PSE are allowed to retain the lesser of the total REP Settlement payments received or the recalculated REP benefits the utilities would have received, but not less than the amount of the LRA payments. By taking this approach, BPA's proposal effectively treats the LRA payments to PacificCorp and PSE as "protected" payments that are not subject to recovery through the Lookback.

#### 15.2.4 Treatment of the Reduction of Risk Discount

In *Snohomish*, the Court determined that the Reduction of Risk Discount was actually a part of the REP Settlement Agreements. *See* Bliven, *et al.*, WP-07-E-BPA-52. In the Lookback analysis, the Reduction of Risk Discount payments are treated in the same manner as payments made under the REP Settlement Agreements. Payments that were made, or would have been made, to PacifiCorp and PSE for the Reduction of Risk Discount are not "protected" and are therefore included in the calculation of the settlement benefits.

#### 15.2.5 Results

The rules stated above are applied on an annual basis to calculate the annual Lookback Amounts for each IOU for FY 2002-2008. In the Lookback analysis, the annual Lookback Amounts for FY 2002-2006 are escalated to 2007 dollars in order to adjust for the effects of inflation. *See* Bliven, *et al.*, WP-07-E-BPA-52. Table 15.4 shows the resulting cumulative Lookback Amounts for each IOU, in 2007 dollars for FY 2002-2007.

**Table 15.4**
**Proposed Lookback Amounts for FY 2002-2007**
(millions of 2007 dollars)

| | |
|---|---|
| Avista | 62.14 |
| Idaho Power | 96.56 |
| NorthWestern Energy | 7.69 |
| PacifiCorp | 239.41 |
| Portland General Electric | 64.13 |
| Puget Sound Energy | 150.55 |
| Total | 620.48 |

Portland General's amounts in the Lookback analysis include a valuation of Portland General's Subscription Agreement power purchases for FY 2006 of $75,048,885 informally provided to BPA by Portland General on December 18, 2007. On February 12, 2008, Portland General provided BPA with its "official" annual certification statement, which included a revised valuation for this power of $89,795,329. BPA did not have time to incorporate this revised information into this Lookback analysis. This revised valuation will be incorporated into BPA's final Supplemental Proposal. See Section 13 for additional information regarding valuation of the Portland General Subscription Agreement power purchase.

In FY 2007, IOUs were paid $168.4 million in REP settlement benefits prior to suspension of payments following the Court's May 2007 rulings. The Lookback analysis indicates that $185.9 million in REP settlement benefits should have been provided to the IOUs for FY 2007. The difference between these amounts, $17.5 million of additional REP benefits for the IOUs, is reflected in the calculation of the $620.5 million total Lookback Amount shown in Table 15.4. Therefore, the IOUs, with the exception of Idaho Power, receive the benefit of the $17.5 million in the form of reduced Lookback Amounts.

Table 15.4 shows cumulative Lookback Amounts for each IOU assuming that BPA offers, and qualifying IOUs sign, Residential Exchange Interim Relief Agreements (Interim Agreements).

If offered and signed, these Interim Agreements would provide interim payments to IOUs for FY 2008. These interim payments are subject to a true-up to the REP benefits IOUs are allowed to keep for FY 2008 determined in this Supplemental Proceeding. The true-up (additional payments by BPA to IOUs or return of a portion the Interim Agreement payments by IOUs to BPA) will be governed by the terms and conditions of the Interim Agreements. The Supplemental Proposal indicates that the amount of FY 2008 REP benefits IOUs are allowed to keep is $188.9 million.

In the absence of Interim Agreements, no vehicle exists by which to deliver REP benefits to the IOUs in FY 2008. In this instance, or if an IOU does not sign an Interim Agreement, the unpaid REP benefits are proposed to be rolled into the respective utility's Lookback Amount, which reduces the aggregate Lookback Amount by $188.9 million.

Tables 15.5 through 15.11 summarize the annual and cumulative Lookback calculations for each IOU. The Total column in these tables is the cumulative Lookback Amount from 2002 through 2007B. These tables are extracted from Lookback Documentation, WP-07-E-BPA-44A, Table 15.3. Table 15.3 includes detailed footnotes that describe how line item amounts are calculated or used to determine Lookback Amounts in a given year.

**Table 15.5**
**Avista Lookback Amount Computation**
(millions of dollars)

| | 2002 | 2003 | 2004 | 2005 | 2006 | 2007A | 2007B | 2008 | Total |
|---|---|---|---|---|---|---|---|---|---|
| Settlement Payments | 11.81 | 8.98 | 11.9 | 11.82 | 11.92 | 10.58 | 0 | 0 | 67.01 |
| Unpaid Settlement | 0 | 0 | 0 | 0 | 0 | 0 | 10.56 | 21.01 | 10.56 |
| REP Benefits | 0 | 0 | 0 | 0 | 0 | 0 | 9.76 | 33.01 | 9.76 |
| Amount Kept | 0 | 0 | 0 | 0 | 0 | 0 | 9.76 | 21.01 | 9.76 |
| nominal$ Lookback | 11.81 | 8.98 | 11.9 | 11.82 | 11.92 | 10.58 | -9.76 | -21.01 | 57.24 |
| 2007$ Lookback | 13.54 | 10.08 | 12.99 | 12.49 | 12.22 | 10.58 | -9.76 | -21.01 | 62.14 |

**Table 15.6**
**Idaho Power Lookback Amount Computation**
(millions of dollars)

| | 2002 | 2003 | 2004 | 2005 | 2006 | 2007A | 2007B | 2008 | Total |
|---|---|---|---|---|---|---|---|---|---|
| Settlement Payments | 14.57 | 12.04 | 15.93 | 15.80 | 15.95 | 15.89 | 0 | 0 | 90.18 |
| Unpaid Settlement | 0 | 0 | 0 | 0 | 0 | 0 | 15.87 | 31.58 | 15.87 |
| REP Benefits | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Amount Kept | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| nominal$ Amount | 14.57 | 12.04 | 15.93 | 15.80 | 15.95 | 15.89 | 0 | 0 | 90.18 |
| 2007$ Lookback | 16.71 | 13.52 | 17.39 | 16.71 | 16.35 | 15.89 | 0 | 0 | 96.56 |

**Table 15.7**
**NorthWestern Lookback Amount Computation**
(millions of dollars)

| | 2002 | 2003 | 2004 | 2005 | 2006 | 2007A | 2007B | 2008 | Total |
|---|---|---|---|---|---|---|---|---|---|
| Settlement Payments | 3.11 | 2.38 | 3.16 | 3.14 | 3.17 | 2.00 | 0 | 0 | 16.94 |
| Unpaid Settlement | 0 | 0 | 0 | 0 | 0 | 0 | 1.99 | 3.95 | 1.99 |
| REP Benefits | 0 | 0 | 0 | 6.31 | 11.08 | 4.61 | 4.61 | 10.25 | 26.62 |
| Amount Kept | 0 | 0 | 0 | 3.14 | 3.17 | 2.00 | 1.99 | 3.95 | 10.29 |
| nominal$ Lookback | 3.11 | 2.38 | 3.16 | 0 | 0 | 0 | -1.99 | -3.95 | 6.65 |
| 2007$ Lookback | 3.56 | 2.67 | 3.45 | 0 | 0 | 0 | -1.99 | -3.95 | 7.69 |

**Table 15.8**
**PacifiCorp Lookback Amount Computation**
(millions of dollars)

| | 2002 | 2003 | 2004 | 2005 | 2006 | 2007A | 2007B | 2008 | Total |
|---|---|---|---|---|---|---|---|---|---|
| Settlement Payments | 37.85 | 26.26 | 37.95 | 37.85 | 37.85 | 46.29 | 0 | 0 | 224.04 |
| Unpaid Settlement | 0 | 0 | 0 | 0 | 0 | 0 | 46.29 | 92.58 | 46.29 |
| REP Benefits | 0 | 0 | 17.12 | 22.1 | 5.46 | 0 | 0 | 4.08 | 44.68 |
| Amount Kept | 79.22 | 83.14 | 83.37 | 83.14 | 83.14 | 0 | 0 | 4.08 | 412 |
| nominal$ Lookback | 37.85 | 26.26 | 37.95 | 37.85 | 37.85 | 46.29 | 0 | -4.08 | 224.04 |
| 2007$ Lookback | 43.4 | 29.49 | 41.42 | 40.02 | 38.79 | 46.29 | 0 | -4.08 | 239.41 |

**Table 15.9**
**Portland General Lookback Amount Computation**
(millions of dollars)

| | 2002 | 2003 | 2004 | 2005 | 2006 | 2007A | 2007B | 2008 | Total |
|---|---|---|---|---|---|---|---|---|---|
| Settlement Payments | 59.01 | 43.62 | 62.46 | 87.65 | 113.56 | 39.47 | 0 | 0 | 405.76 |
| Unpaid Settlement | 0 | 0 | 0 | 0 | 0 | 0 | 39.79 | 78.95 | 39.79 |
| REP Benefits | 94.42 | 38.91 | 45.50 | 62.92 | 75.91 | 31.93 | 31.93 | 51.56 | 381.52 |
| Amount Kept | 59.10 | 38.91 | 45.50 | 62.92 | 75.91 | 31.93 | 31.93 | 51.56 | 64.13 |
| nominal$ Lookback | 0 | 4.71 | 16.95 | 24.73 | 37.65 | 7.53 | -31.93 | -51.56 | 59.64 |
| 2007$ Lookback | 0 | 5.29 | 18.50 | 26.14 | 38.59 | 7.53 | -31.93 | -51.56 | 64.13 |

**Table 15.10**
**Puget Sound Lookback Amount Computation**
(millions of dollars)

| | 2002 | 2003 | 2004 | 2005 | 2006 | 2007A | 2007B | 2008 | Total |
|---|---|---|---|---|---|---|---|---|---|
| Settlement Payments | 56.11 | 28.42 | 56.27 | 56.11 | 56.11 | 54.15 | 0 | 0 | 307.18 |
| Unpaid Settlement | 0 | 0 | 0 | 0 | 0 | 0 | 54.15 | 108.32 | 54.15 |
| REP Benefits | 92.80 | 44.79 | 94.81 | 134.14 | 180.65 | 72.41 | 72.41 | 135.11 | 692.02 |
| Amount Kept | 116.67 | 122.50 | 122.84 | 134.14 | 178.61 | 54.15 | 54.15 | 108.32 | 783.06 |
| nominal$ Lookback | 56.11 | 28.42 | 56.27 | 44.47 | 0 | 0 | -54.15 | -108.32 | 131.12 |
| 2007$ Lookback | 64.35 | 31.91 | 61.42 | 47.02 | 0 | 0 | -54.15 | -108.32 | 150.55 |

**Table 15.11**
**Composite Lookback Amount Computation**
(millions of dollars)

| | 2002 | 2003 | 2004 | 2005 | 2006 | 2007A | 2007B | 2008 | Total |
|---|---|---|---|---|---|---|---|---|---|
| Settlement Payments | 182.45 | 121.69 | 187.67 | 212.36 | 238.56 | 168.38 | 0 | 0 | 1,111.10 |
| Unpaid Settlement | 0 | 0 | 0 | 0 | 0 | 0 | 168.65 | 336.39 | 168.65 |
| REP Benefits | 187.22 | 83.69 | 157.44 | 225.47 | 273.10 | 108.96 | 118.72 | 234.01 | 1,270.52 |
| Amount Kept | 254.89 | 244.54 | 251.71 | 283.33 | 340.82 | 88.08 | 97.84 | 188.92 | 1,561.23 |
| nominal$ Lookback | 123.44 | 82.79 | 142.16 | 134.66 | 103.37 | 80.29 | -97.84 | -188.92 | 568.87 |
| 2007$ Lookback | 141.56 | 92.96 | 155.17 | 142.39 | 105.95 | 80.29 | -97.84 | -188.92 | 620.48 |

## 15.3 Recovery of IOU Lookback Amounts

Because the IOUs have already passed through to their residential and small farm customers the payments made under the REP settlements, BPA proposes to recover Lookback Amounts from the IOUs by reducing future REP benefits determined to be otherwise due them. The amount of the reduction in benefits for the relevant rate period will be determined by the Administrator in each rate proceeding. This reduction is achieved by establishing a limit on the REP benefits to be paid each year. Each IOU would receive payments up to its respective REP benefit limit.

### 15.3.1 REP Benefit Annual Limit

Given that REP benefits are determined, in part, by actual exchange loads as they occur, it is possible for actual REP benefits paid to be less than the REP benefit limit established for the rate period. The reduction in the amounts of REP benefits that would have otherwise been provided, which is equal to the calculated REP benefits capped at the REP benefit limit, shall be the actual amount credited against each IOU's remaining Lookback Amount. This approach allows for each IOU's Lookback Amount to be tracked over time. The approach would continue, as needed, each month until each IOU has repaid its total Lookback Amount, including accrued interest. The REP benefit limits proposed for FY 2009 are based on the intent to fully amortize each IOU's Lookback Amount within 20 years or less, with the exception of Idaho Power. The assumptions and proposal for Idaho Power are described in more detail below.

BPA proposes to establish each IOU's REP benefit limit for FY 2009 by proportionally reducing each IOU's FY 2009 REP benefits such that the aggregate payment limit is $210 million, before consideration of deemer obligations. The FY 2009 pre-limit REP benefits are described in Brodie, *et al.*, WP-07-E-BPA-70 and shown in the Supplemental WPRDS Documentation, WP-07-E-BPA-49A, Table 2.9. The adjustment for deemer obligations reduces the total REP benefits included in proposed FY 2009 rates to $202.3 million. Table 15.12 summarizes FY 2009 REP benefits, before and after application of REP benefit limits, and the adjustment for deemer obligations. It also shows the expected amount of Lookback obligations remaining at the end of FY 2009, including interest as described below.

**Table 15.12**
**Summary of FY 2009 REP Benefits**
(millions of dollars)

| | FY 2009 Pre-Limit REP Benefits | REP Benefits at Limit before Deemer Adjustment | REP Benefits at Limit after Deemer Adjustment | Expected REP Benefits applied to Lookback | FY 2010 Unamortized Lookback Amount (Est) |
|---|---|---|---|---|---|
| Avista Energy | 27.8 | 23.3 | 23.3 | 4.5 | 60.7 |
| Idaho Power | 9.2 | 7.7 | 0.0 | 0.0 | 101.4 |
| NorthWestern | 7.6 | 6.4 | 6.4 | 1.2 | 6.8 |
| PacifiCorp | 50.8 | 42.7 | 42.7 | 8.1 | 243.1 |
| Portland General | 54.6 | 45.8 | 45.8 | 8.8 | 58.4 |
| Puget Sound | 100.2 | 84.1 | 84.1 | 16.1 | 141.6 |
| Total | 250.2 | 210.0 | 202.3 | 38.7 | 612.0 |

### 15.3.2 Accrual of Interest

BPA proposes that remaining Lookback balances should accrue interest. The rate of interest will be determined each rate period. The interest rate proposed for FY 2009 is 5.03 percent. This rate is the average daily 20-year Treasury bill rate for the period starting October 1, 2001, and ending September 30, 2007. In the WP-10 rate proceeding, the unamortized Lookback obligations will be increased by the accrued interest. The procedures used to apply the interest to the unamortized Lookback obligations will be determined in that rate proceeding.

### 15.3.3 Recovery of the Lookback Amounts: the LBLF Model

Table 15.4 shows the proposed Lookback Amount for each IOU. Table 15.11 shows the expected Lookback Amount for each IOU after FY 2009. Circumstances differ among the utilities, and the calculations of annual Lookback Amounts reflect these differences. Avista, NorthWestern and Idaho Power all had outstanding deemer balances as of October 2001. Calculation of their annual Lookback Amounts therefore reflects the treatment of deemer balances described in Section 15.2.1. All IOUs are subject to the settlement payments cap described in Section 15.2.2, as modified by the treatment of LRA payments described in Section 15.2.3.

The LBLF model, *see* Section 15.2, includes the capability to look forward in a simplistic manner to assess the potential amortization of each IOU's Lookback Amount through time. The LBLF model can use either an externally produced stream of REP benefits, or it can generate an escalated stream of REP benefits through FY 2028. *See* Table 15.1, points 1.h through 1.k.

The individual IOU REP benefit limits, combined with two simple assumptions, result in all IOUs, except Idaho Power, amortizing their respective Lookback Amounts within 20 years or less. The first assumption is that each IOU's FY 2009 REP benefit amount will increase by

2.5 percent per year (as a consequence of growth in eligible exchange loads and/or increases in IOU ASCs and/or changes in PF Exchange rates, none of which is specifically forecast or otherwise modeled). Second, interest accrues on unamortized Lookback balances at the rate of 5.03 percent per year. Table 15.13 shows the year that Lookback Amounts are fully amortized based on the simple assumptions above, with the exception of Idaho Power.

**Table 15.13**
**Projected Year Lookback Amounts are Fully Amortized**

| | |
|---|---|
| Avista | 2019 |
| Idaho Power | not amortized |
| NorthWestern Energy | 2014 |
| PacifiCorp | 2027 |
| Portland General Electric | 2015 |
| Puget Sound Energy | 2016 |

### 15.3.4 Recovery of the Lookback Amounts: Idaho Power

Idaho Power has a deemer balance at the end of FY 2007 of approximately $243.7 million. Assuming that Idaho Power executes an RPSA for FY 2009 and beyond, BPA proposes to apply a comparable treatment to Idaho Power's deemer obligation as that used for Avista and Northwestern in determining their Lookback Amounts. That is, BPA will apply any pre-limit REP benefits for FY 2009 as an offset to reduce Idaho Power's deemer balance. For FY 2009, Idaho would receive credit for the full REP benefit, expected to be about $9.2 million, against their deemer obligation. Only when Idaho Power's deemer balance is extinguished would REP benefits be available to amortize its Lookback Amount and to provide REP benefits to Idaho Power's residential consumers. However, assuming all of Idaho Power's REP benefits are used to first pay down its deemer obligation, under the simple projections outlined above, Idaho Power will not fully amortize its Lookback Amount by 2028. A more rigorous projection of Idaho Power's future conditions, including higher load growth than the other IOUs, could result in a reasonable expectation that Idaho Power might fully amortize its Lookback Amount by

2028. BPA acknowledges that Idaho Power disputes its current deemer balance. BPA further recognizes that Idaho Power has requested that BPA consider the possibility of settling this dispute prior to or concurrent with the offer of a new RPSA. To the extent that BPA engages in such discussions with Idaho Power, it will do so outside this 7(i) proceeding.

### 15.4 Return of FY 2002-2006 Overcharges to COUs

As constructed in this determination, the FY 2002-2006 Lookback Amounts constitute the entirety of the amount of REP settlement costs inappropriately included in the rates to COUs in response to the *Golden NW* remand. BPA proposes to return Lookback Amounts to the COUs by reducing future REP benefits paid to IOUs. The implementation of REP benefit limits described in Section 15.3.1 results in lower PF Preference rates for FY 2009 and beyond until Lookback Amounts are fully amortized. Specifically for FY 2009, $202.3 million in REP benefits is included in determination of the FY 2009 PF Preference rate. The lower FY 2009 PF Preference rate results from the application of a portion of the REP Benefits due to reduce Lookback Amounts and the set off of Idaho Power's deemer balance.

The $40.2 million reduction in REP benefits included in the PF Preference rate is the first installment in returning Lookback Amounts to COUs. Additional installments will be included in future rates. In this way, COUs are being compensated for the amounts they were overcharged due to the REP settlement costs that were inappropriately included in rates for COUs.

### 15.5 Return of FY 2007-2008 Overcharges to COUs

For FY 2007-2008, REP settlement costs have been and continue to be included in preference customer rates. However, BPA suspended settlement payments to the IOUs in May 2007, and will have accumulated $505 million in unpaid REP settlement costs as cash in its reserves by the end of October 2008 (when the September payment would have been made). Since this cash is in the BPA Fund, return of FY 2007-2008 overcharges to COUs is not contingent on reductions in future REP benefits paid to IOUs, as is the case for the Lookback Amounts.

BPA proposes to return the amounts that COUs were overcharged in the PF Preference rate for FY 2007-2008 plus the $17.5 million owed but not paid to IOUs described in Section 15.2.5 by providing cash payments (or cash equivalent, under certain circumstances, as described below) to the COUs in FY 2008 and/or FY 2009. For FY 2007, $337.0 million in REP settlement costs were included in the PF Preference rate. *See* Table 13.2 in this Study. The Lookback analysis has calculated that the total IOU REP benefits for FY 2007 are $227.7 million. *See* Table 15.11. After application of the Lookback rules discussed in Sections 15.2.1 and 15.2.2, the REP benefits IOUs get to keep for FY 2007 are $185.9 million. BPA proposes to refund the difference between $337.0 million and $185.0 million, or $151.1 million, to COUs for FY 2007.

In addition, as noted above, $168.4 million of the $185.9 million in REP benefits the IOUs get to keep has been paid to IOUs in FY 2007. BPA has included the difference between what IOUs have already been paid and the REP benefits they get to keep, $17.5 million, in the FY2002-2007 Lookback Amounts. Including the $17.5 million in the Lookback Amount (as a reduction to what the Lookback Amount would be absent including this amount) returns it to the IOUs, but is not a cash cost to BPA. BPA proposes to include the $17.5 million as additional cash in the amount paid to COUs rather than retain it in cash reserves. This makes the total amount proposed to be repaid to the COUs for FY 2007 equal $168.6 million.

For FY 2008, $336.4 million in REP settlement costs were included in the PF Preference rate. As seen in Table 15.11, BPA proposes that $188.9 million in REP benefits should be provided to the IOUs. Therefore, BPA proposes to pay COUs the difference between $188.9 million and

$336.4 million, or $147.5 million, as a return of their overcharges for FY 2008. The total amount to be returned to COUs for FY 2007-2008 is therefore $316.1 million.

BPA proposes the following methodology to determine the non-Slice and Slice portions of the $316.1 million. First, the $316.1 million is divided between non-Slice and Slice purchasers on a 77.3722 percent / 22.6278 percent basis. This results in a non-Slice amount of $244.6 million and a Slice amount of $71.5 million. For clarity and consistency with the proposed Standstill Agreements that BPA may offer, these amounts are hereafter referred to as the Non-Slice Definitive Payment Amount and the Slice Definitive Payment Amount, respectively.

**Table 15.14**
**Definitive Payment Amounts**
(millions of dollars)

| | | |
|---|---|---|
| FY 2007 Overcharge | 151.10 | |
| FY 2007 Lookback Set Off | 17.55 | |
| FY 2008 Overcharge | 147.46 | |
| Total | 316.11 | |
| Non-Slice Definitive Payment Amount | 244.58 | 77.3722% of Total |
| Slice Definitive Payment Amount | 71.53 | 22.6278% of Total |

Generally speaking, BPA proposes to determine the amount returned to each COU on the customer's share of FY 2007 Priority Firm revenue including PF Slice, PF HLH Energy, PF LLH Energy, PF Demand, PF Load Variance, Irrigation Rate Mitigation Product, Conservation Incentive, Conservation Rate Credit and Low Density Discount, but excluding any FY 2007 Slice True-up amounts. These shares are calculated from the respective final (or revised final, if applicable) amounts each COU was billed for FY 2007. Because of the differences between the Slice product and its applicable rate and the Non-Slice products and their applicable rates, the amounts returned to each customer are based on separate calculations for Slice and Non-Slice components. The manner in which the Slice and Non-Slice amounts are returned also differs because of the Slice True-Up.

BPA proposes that individual Customer Payment Amounts be calculated by applying percentages to the Non-Slice Definitive Payment Amount and the Slice Definitive Payment Amount. For each customer, its non-Slice percentage is equal to the ratio of BPA's FY 2007 PF non-Slice revenues from each such customer to total non-Slice PF revenues, both of which would include Block purchases by Slice customers. For each Slice customer, its Slice percentage is equal to the ratio of the FY 2007 PF Slice revenues from each such customer to total Slice revenues, excluding any FY 2007 Annual Slice True-Up amounts. The individual customer non-Slice and Slice revenues, percentages and Customer Payment Amounts are provided in Table 15.15, Customer Payment Amounts, below.

For COUs that sign Standstill Agreements, Customer Payment Amounts would be provided according to the terms and conditions of those agreements. For COUs that have not entered into Standstill Agreements, BPA proposes that Customer Payment Amounts would be provided as follows. The non-Slice Customer Payment Amounts, plus interest as specified below, would be provided in a lump sum payment by electronic funds transfer (EFT) as soon as practicable after FERC interim approval of the final Supplemental Proposal. The Slice Customer Payment Amounts, plus interest, would be accounted for through the Slice True-Up for FY 2008.

BPA proposes that interest would be added to the Customer Payment Amounts for COUs that have not entered into Standstill Agreements as follows. For the non-Slice Customer Definitive Payment Amounts, interest will be simple interest computed on the non-Slice Standstill Payment Amount in Table 15.15. Interest would accrue from the date of the first Standstill Payment made under any Standstill Agreement, until the date of the payment by EFT of the non-Slice Customer Definitive Payment Amount. For the Slice Customer, Definitive Payment Amount interest is proposed to be simple interest computed on the Slice Standstill Payment Amount in Table 15.14.

Interest would accrue from the date of the first Standstill Payment made under any Standstill Agreement, through September 30, 2008.

The interest rate applicable to the Customer Definitive Payment Amounts would be the six-month annual rate of interest posted under the title "Daily Treasury Yield Curve Rates" as published on the U.S. Department of Treasury web site at 3:30 pm Eastern Prevailing Time on date of the first Standstill Payment. This interest rate is available at the following website: www.treasury.gov/offices/domestic-finance/debt-management/interest-rate/yield.shtml

**Table 15.15.1**
**Customer Payment Amounts**
(dollars)

| | Definitive Payment Amount | | | Standstill Payment Amount | | |
|---|---|---|---|---|---|---|
| | Non-Slice | Slice | Total | Non-Slice | Slice | Total |
| Albion, City of | 17,366 | 0 | 17,366 | 11,273 | 0 | 11,273 |
| Alder Mutual | 21,249 | 0 | 21,249 | 13,794 | 0 | 13,794 |
| Ashland, City of | 980,190 | 0 | 980,190 | 636,275 | 0 | 636,275 |
| Asotin County PUD #1 | 26,312 | 0 | 26,312 | 17,080 | 0 | 17,080 |
| Bandon, City of | 366,787 | 0 | 366,787 | 238,094 | 0 | 238,094 |
| Benton County PUD #1 | 4,272,687 | 5,627,058 | 9,899,745 | 2,773,546 | 3,652,715 | 6,426,261 |
| Benton REA | 2,568,343 | 0 | 2,568,343 | 1,667,199 | 0 | 1,667,199 |
| Big Bend Elec Coop | 2,082,403 | 0 | 2,082,403 | 1,351,759 | 0 | 1,351,759 |
| Big Horn County Electric Coop | 0 | 0 | 0 | 0 | 0 | 0 |
| Blachly Lane Elec Coop | 0 | 213,211 | 213,211 | 0 | 138,402 | 138,402 |
| Blaine, City of | 397,797 | 0 | 397,797 | 258,223 | 0 | 258,223 |
| Bonners Ferry, City of | 255,564 | 0 | 255,564 | 165,896 | 0 | 165,896 |
| Burley, City of | 636,361 | 0 | 636,361 | 413,084 | 0 | 413,084 |
| Canby, City of | 926,390 | 0 | 926,390 | 601,351 | 0 | 601,351 |
| Cascade Locks, City of | 117,677 | 0 | 117,677 | 76,388 | 0 | 76,388 |
| Central Electric Coop | 0 | 744,468 | 744,468 | 0 | 483,260 | 483,260 |
| Central Lincoln PUD | 6,796,296 | 0 | 6,796,296 | 4,411,707 | 0 | 4,411,707 |
| Cent. Montana Elec Power Coop | 0 | 0 | 0 | 0 | 0 | 0 |
| Centralia, City of | 1,089,004 | 0 | 1,089,004 | 706,910 | 0 | 706,910 |
| Cheney, City of | 683,209 | 0 | 683,209 | 443,494 | 0 | 443,494 |
| Chewelah, City of | 134,222 | 0 | 134,222 | 87,128 | 0 | 87,128 |
| Clallam County PUD #1 | 3,514,579 | 0 | 3,514,579 | 2,281,433 | 0 | 2,281,433 |
| Clark County PUD #1 | 19,151,534 | 0 | 19,151,534 | 12,431,914 | 0 | 12,431,914 |
| Clatskanie PUD | 1,813,602 | 3,111,670 | 4,925,272 | 1,177,271 | 2,019,891 | 3,197,162 |
| Clearwater Power | 0 | 266,569 | 266,569 | 0 | 173,039 | 173,039 |
| Columbia Basin Elec Coop | 466,170 | 0 | 466,170 | 302,607 | 0 | 302,607 |
| Columbia Power Coop | 129,329 | 0 | 129,329 | 83,952 | 0 | 83,952 |
| Columbia REA | 1,171,137 | 0 | 1,171,137 | 760,225 | 0 | 760,225 |
| Columbia River PUD | 2,791,895 | 0 | 2,791,895 | 1,812,314 | 0 | 1,812,314 |
| Consolidated Irrigation Dist #19 | 9,983 | 0 | 9,983 | 6,480 | 0 | 6,480 |
| Consumers Power | 0 | 470,639 | 470,639 | 0 | 305,508 | 305,508 |
| Coos Curry Elec Coop | 0 | 430,181 | 430,181 | 0 | 279,245 | 279,245 |
| Coulee Dam, City of | 103,327 | 0 | 103,327 | 67,073 | 0 | 67,073 |
| Cowlitz County PUD #1 | 22,587,827 | 0 | 22,587,827 | 14,662,528 | 0 | 14,662,528 |
| Declo, City of | 16,396 | 0 | 16,396 | 10,643 | 0 | 10,643 |
| Douglas County PUD #1 | 0 | 0 | 0 | 0 | 0 | 0 |
| Douglas Electric Cooperative | 0 | 211,297 | 211,297 | 0 | 137,160 | 137,160 |
| Drain, City of | 116,016 | 0 | 116,016 | 75,310 | 0 | 75,310 |
| East End Mutual Electric | 101,313 | 0 | 101,313 | 65,766 | 0 | 65,766 |
| Eatonville, City of | 158,032 | 0 | 158,032 | 102,584 | 0 | 102,584 |
| Ellensburg, City of | 1,121,059 | 0 | 1,121,059 | 727,717 | 0 | 727,717 |
| Elmhurst Mutual P & L | 1,504,964 | 0 | 1,504,964 | 976,924 | 0 | 976,924 |
| Emerald County PUD | 2,434,864 | 0 | 2,434,864 | 1,580,554 | 0 | 1,580,554 |
| Energy Northwest | 133,975 | 0 | 133,975 | 86,968 | 0 | 86,968 |
| Eugene Water & Electric | 5,330,067 | 7,760,170 | 13,090,237 | 3,459,928 | 5,037,391 | 8,497,319 |

**Table 15.15.2**
**Customer Payment Amounts**
(dollars)

| | Definitive Payment Amount | | | Standstill Payment Amount | | |
|---|---|---|---|---|---|---|
| | Non-Slice | Slice | Total | Non-Slice | Slice | Total |
| Fairchild AFB | 342,057 | 0 | 342,057 | 222,041 | 0 | 222,041 |
| Fall River Elec Coop | 0 | 237,978 | 237,978 | 0 | 154,480 | 154,480 |
| Farmers Elec Coop | 21,435 | 0 | 21,435 | 13,914 | 0 | 13,914 |
| Ferry County PUD #1 | 351,881 | 0 | 351,881 | 228,418 | 0 | 228,418 |
| Flathead Elec Coop | 7,683,772 | 0 | 7,683,772 | 4,987,798 | 0 | 4,987,798 |
| Forest Grove, City of | 1,227,459 | 0 | 1,227,459 | 796,786 | 0 | 796,786 |
| Franklin County PUD #1 | 1,935,798 | 2,504,281 | 4,440,079 | 1,256,593 | 1,625,614 | 2,882,207 |
| Glacier Elec Coop | 0 | 0 | 0 | 0 | 0 | 0 |
| Grant County PUD #2 | 8,246,183 | 0 | 8,246,183 | 5,352,879 | 0 | 5,352,879 |
| Grays Harbor PUD #1 | 2,384,859 | 3,725,961 | 6,110,820 | 1,548,093 | 2,418,648 | 3,966,741 |
| Harney Elec Coop | 809,325 | 0 | 809,325 | 525,360 | 0 | 525,360 |
| Hermiston, City of | 594,044 | 0 | 594,044 | 385,614 | 0 | 385,614 |
| Heyburn, City of | 206,771 | 0 | 206,771 | 134,222 | 0 | 134,222 |
| Hood River Elec Coop | 610,674 | 0 | 610,674 | 396,409 | 0 | 396,409 |
| Idaho County L & P | 257,940 | 0 | 257,940 | 167,437 | 0 | 167,437 |
| Idaho Falls, City of | 1,327,649 | 2,210,822 | 3,538,471 | 861,822 | 1,435,120 | 2,296,942 |
| Inland P & L | 4,291,713 | 0 | 4,291,713 | 2,785,897 | 0 | 2,785,897 |
| Kittitas County PUD #1 | 355,825 | 0 | 355,825 | 230,978 | 0 | 230,978 |
| Klickitat County PUD #1 | 1,412,231 | 0 | 1,412,231 | 916,727 | 0 | 916,727 |
| Kootenai Electric Coop | 2,201,892 | 0 | 2,201,892 | 1,429,323 | 0 | 1,429,323 |
| Lakeview L & P (WA) | 1,549,956 | 0 | 1,549,956 | 1,006,129 | 0 | 1,006,129 |
| Lane County Elec Coop | 0 | 306,799 | 306,799 | 0 | 199,154 | 199,154 |
| Lewis County PUD #1 | 4,917,950 | 0 | 4,917,950 | 3,192,409 | 0 | 3,192,409 |
| Lincoln Elec Coop | 0 | 0 | 0 | 0 | 0 | 0 |
| Lost River Elec Coop | 0 | 79,617 | 79,617 | 0 | 51,682 | 51,682 |
| Lower Valley P & L | 3,251,811 | 0 | 3,251,811 | 2,110,861 | 0 | 2,110,861 |
| Mason County PUD #1 | 389,390 | 0 | 389,390 | 252,766 | 0 | 252,766 |
| Mason County PUD #3 | 3,595,310 | 0 | 3,595,310 | 2,333,838 | 0 | 2,333,838 |
| McCleary, City of | 197,229 | 0 | 197,229 | 128,028 | 0 | 128,028 |
| McMinnville, City of | 4,574,406 | 0 | 4,574,406 | 2,969,403 | 0 | 2,969,403 |
| Midstate Elec Coop | 1,959,658 | 0 | 1,959,658 | 1,272,081 | 0 | 1,272,081 |
| Milton Freewater, City of | 464,250 | 0 | 464,250 | 301,360 | 0 | 301,360 |
| Milton, Town of | 345,943 | 0 | 345,943 | 224,563 | 0 | 224,563 |
| Minidoka, City of | 4,853 | 0 | 4,853 | 3,150 | 0 | 3,150 |
| Mission Valley | 0 | 0 | 0 | 0 | 0 | 0 |
| Missoula Elec Coop | 0 | 0 | 0 | 0 | 0 | 0 |
| Modern Elec Coop | 1,249,573 | 0 | 1,249,573 | 811,141 | 0 | 811,141 |
| Monmouth, City of | 378,339 | 0 | 378,339 | 245,593 | 0 | 245,593 |
| Nespelem Valley Elec Coop | 237,153 | 0 | 237,153 | 153,944 | 0 | 153,944 |
| Northern Lights | 0 | 208,055 | 208,055 | 0 | 135,056 | 135,056 |
| Northern Wasco County PUD | 2,607,498 | 0 | 2,607,498 | 1,692,616 | 0 | 1,692,616 |
| Ohop Mutual Light Company | 443,451 | 0 | 443,451 | 287,859 | 0 | 287,859 |
| Okanogan County Elec Coop | 0 | 59,065 | 59,065 | 0 | 38,341 | 38,341 |
| Okanogan County PUD #1 | 1,007,970 | 1,579,250 | 2,587,220 | 654,308 | 1,025,145 | 1,679,453 |
| Orcas P & L | 1,111,619 | 0 | 1,111,619 | 721,590 | 0 | 721,590 |
| Oregon Trail Coop | 3,551,075 | 0 | 3,551,075 | 2,305,124 | 0 | 2,305,124 |

**Table 15.15.3**
**Customer Payment Amounts**
(dollars)

| | Definitive Payment Amount | | | Standstill Payment Amount | | |
|---|---|---|---|---|---|---|
| | Non-Slice | Slice | Total | Non-Slice | Slice | Total |
| Pacific County PUD #2 | 1,710,648 | 0 | 1,710,648 | 1,110,440 | 0 | 1,110,440 |
| Parkland L & W | 665,472 | 0 | 665,472 | 431,981 | 0 | 431,981 |
| Pend Oreille County PUD #1 | 73,736 | 1,218,170 | 1,291,906 | 47,865 | 790,756 | 838,621 |
| Peninsula Light Company | 3,165,561 | 0 | 3,165,561 | 2,054,874 | 0 | 2,054,874 |
| Plummer, City of | 179,773 | 0 | 179,773 | 116,696 | 0 | 116,696 |
| PNGC | 8,660,423 | 8,206,918 | 16,867,341 | 5,621,776 | 5,327,390 | 10,949,166 |
| Port Angeles, City of | 3,704,782 | 0 | 3,704,782 | 2,404,900 | 0 | 2,404,900 |
| Port of Seattle | 766,882 | 0 | 766,882 | 497,809 | 0 | 497,809 |
| PSNS (Bremerton) | 1,292,493 | 0 | 1,292,493 | 839,001 | 0 | 839,001 |
| Raft River Elec Coop | 0 | 127,984 | 127,984 | 0 | 83,079 | 83,079 |
| Ravalli County Elec Coop | 0 | 0 | 0 | 0 | 0 | 0 |
| Richland, City of | 4,527,221 | 0 | 4,527,221 | 2,938,774 | 0 | 2,938,774 |
| Riverside Elec Coop | 91,713 | 0 | 91,713 | 59,534 | 0 | 59,534 |
| Rupert, City of | 410,400 | 0 | 410,400 | 266,405 | 0 | 266,405 |
| Salem Elec Coop | 1,854,687 | 0 | 1,854,687 | 1,203,941 | 0 | 1,203,941 |
| Salmon River Elec Coop | 0 | 254,413 | 254,413 | 0 | 165,148 | 165,148 |
| Seattle City Light | 11,832,408 | 14,888,526 | 26,720,934 | 7,680,820 | 9,664,650 | 17,345,470 |
| Skamania County PUD #1 | 721,478 | 0 | 721,478 | 468,336 | 0 | 468,336 |
| Snohomish County PUD #1 | 15,849,197 | 15,926,157 | 31,775,354 | 10,288,254 | 10,338,211 | 20,626,465 |
| Soda Springs, City of | 129,242 | 0 | 129,242 | 83,896 | 0 | 83,896 |
| Southern MT G&T | 0 | 0 | 0 | 0 | 0 | 0 |
| Southside Elec Lines | 244,262 | 0 | 244,262 | 158,559 | 0 | 158,559 |
| Springfield Utility Board | 4,549,488 | 0 | 4,549,488 | 2,953,228 | 0 | 2,953,228 |
| Steilacoom, Town of | 225,422 | 0 | 225,422 | 146,329 | 0 | 146,329 |
| Sumas, Town of | 162,404 | 0 | 162,404 | 105,422 | 0 | 105,422 |
| Surprise Valley Elec Coop | 632,044 | 0 | 632,044 | 410,281 | 0 | 410,281 |
| Tacoma Public Utilities | 19,964,888 | 0 | 19,964,888 | 12,959,889 | 0 | 12,959,889 |
| Tanner Elec Coop | 382,779 | 0 | 382,779 | 248,475 | 0 | 248,475 |
| Tillamook PUD #1 | 2,419,683 | 0 | 2,419,683 | 1,570,699 | 0 | 1,570,699 |
| Troy, City of | 0 | 0 | 0 | 0 | 0 | 0 |
| U.S. DOE Albany | 21,106 | 0 | 21,106 | 13,701 | 0 | 13,701 |
| U.S.N. Everett (Jim Creek) | 67,489 | 0 | 67,489 | 43,809 | 0 | 43,809 |
| U.S. N. Bangor | 914,628 | 0 | 914,628 | 593,716 | 0 | 593,716 |
| Umatilla Elec Coop | 0 | 1,061,642 | 1,061,642 | 0 | 689,148 | 689,148 |
| Umpqua Indian Utility Coop | 114,593 | 0 | 114,593 | 74,387 | 0 | 74,387 |
| United Electric Coop | 914,449 | 0 | 914,449 | 593,600 | 0 | 593,600 |
| USBIA Wapato | 75,093 | 0 | 75,093 | 48,745 | 0 | 48,745 |
| USDOE-Richland | 963,955 | 0 | 963,955 | 625,736 | 0 | 625,736 |
| Vera Irrigation District | 1,234,620 | 0 | 1,234,620 | 801,434 | 0 | 801,434 |
| Vigilante Elec Coop | 0 | 0 | 0 | 0 | 0 | 0 |
| Wahkiakum County PUD #1 | 226,103 | 0 | 226,103 | 146,771 | 0 | 146,771 |
| Wasco Elec Coop | 513,219 | 0 | 513,219 | 333,148 | 0 | 333,148 |
| Weiser, City of | 136,699 | 0 | 136,699 | 88,736 | 0 | 88,736 |
| Wells Rural Elec Coop | 3,848,314 | 0 | 3,848,314 | 2,498,072 | 0 | 2,498,072 |
| West Oregon Elec Coop | 0 | 98,614 | 98,614 | 0 | 64,014 | 64,014 |
| Whatcom County PUD #1 | 1,022,695 | 0 | 1,022,695 | 663,866 | 0 | 663,866 |
| Yakama Power | 186,998 | 0 | 186,998 | 121,387 | 0 | 121,387 |
| Grand TOTAL | 244,583,915 | 71,529,515 | 316,113,430 | 158,767,754 | 46,432,246 | 205,200,000 |

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