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 Final Proposal

FY 2009 WHOLESALE POWER RATE DEVELOPMENT STUDY

September 2008

WP-07-FS-BPA-13

AMENDED TO INCLUDE ERRATA IN BACK OF DOCUMENT

BONNEVILLE POWER ADMINISTRATION

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WHOLESALE POWER RATE DEVELOPMENT 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	Gigawatt-hour
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]

[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.

JP6	Avista Corporation, Idaho Power Corporation, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc.
JP7	NONE
JP8	Northwest Energy Coalition, Save Our *Wild* Salmon
JP9	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, PacifiCorp, Western Public Agencies Group and Members, Avista Corporation, Portland General Electric Company
JP10	Alcoa, Inc., Cowlitz County Public Utility District, Industrial Customers of Northwest Utilities
JP11	Cowlitz County Public Utility District, Eugene Water & Electric Board, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma
JP12	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Western Public Agencies Group and Members, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members
JP13	Columbia River Inter-Tribal Fish Commission, Confederated Tribes and Bands of the Yakama Nation, Nez Perce Tribe
JP14	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Industrial Customers of Northwest Utilities, Northwest Requirements Utilities and Members , Public Power Council, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Springfield Utility Board, Pacific Northwest Generating Cooperative and Members
JP15	Calpine Corporation, Northwest Independent Power Producers Coalition, PPM Energy, Inc., TransAlta Centralia Generation, LLC
kAf	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatt-hour
LB CRAC	Load-Based Cost Recovery Adjustment Clause

LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LOLP	Loss of Load Probability
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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1. INTRODUCTION

1.1 Purpose of the Wholesale Power Rate Development Study

The FY 2009 Wholesale Power Rate Development Study (FY 2009 WPRDS) serves two primary purposes. It synthesizes information supplied by the other studies that comprise the WP-07 Supplemental Final Proposal and shows the calculations for the proposed power rates. In addition, the FY 2009 WPRDS is the primary source for certain information used in establishing the power rates. Information developed in the FY 2009 WPRDS includes rate design (including seasonal and diurnal shapes for energy rates, demand, and load variance rates), the application of risk mitigation tools (Cost Recovery Adjustment Clause (CRAC), as modified by the [**N**]ational Marine Fisheries Service [**F**]ederal Columbia River Power System [**B**]iological Opinion (NFB) Adjustment; the Emergency NFB Surcharge; and the Dividend Distribution Clause (DDC)), development of the Slice rate, and all rate discounts and other adjustments that are included in the 2007 Wholesale Power Rate Schedules (FY 2009) and the 2007 General Rate Schedule Provisions (FY 2009) (GRSPs). The FY 2009 WPRDS also includes the description of the methodology for the Cost of Service Analysis (COSA), and the various rate design steps necessary to establish BPA's power rates. Furthermore, the FY 2009 WPRDS shows the calculations for inter-business line revenues and expenses, the revenue forecast and, finally, includes a description of all the rate schedules. The actual rate schedules are shown in the 2007 Wholesale Power Rate Schedules (FY 2009) and 2007 General Rate Schedule Provisions (FY 2009). *See* 2007 Wholesale Power Rate Schedules (FY 2009) and 2007 General Rate Schedule Provisions (FY 2009), WP-07-A-05A.

The FY 2009 WPRDS also continues implementing the Partial Resolution of Issues with the exception of 7(b)(2) issues. *See* the Partial Resolution of Issues, Attachment 1, Administrator's

Final Record of Decision, WP-07-A-02, July 2006. The Partial Resolution of Issues affected many of the features described in this Study. These are noted where appropriate.

1.2 Overview of the Study

The entire WP-07 Supplemental Final Proposal, including the FY 2009 WPRDS and the other studies and accompanying documentation, provides the details of computations and assumptions required to calculate the proposed rates. In general, information about loads and resources is provided by the FY 2009 Load Resource Study, WP-07-FS-BPA-09, and the FY 2009 Load Resource Study Documentation, WP-07-FS-BPA-09A. Revenue requirement information is provided by the FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10, and the accompanying FY 2009 Revenue Requirement Study Documentation, WP-07-FS-BPA-10A and WP-07-FS-BPA-10B. The FY 2009 Market Price Forecast Study, WP-07-FS-BPA-11, and FY 2009 Market Price Forecast Study Documentation, WP-07-FS-BPA-11A, provide the WPRDS with information regarding electricity market prices used in the WPRDS for seasonal and diurnal differentiation of energy rates, as well as for informing the development of demand rates. In addition, this Study provides information for the pricing of unbundled power products. The FY 2009 Risk Analysis Study, WP-07-FS-BPA-12, and FY 2009 Risk Analysis Study Documentation, WP-07-FS-BPA-12A, provide short-term balancing purchases as well as net secondary energy sales and revenue and risk mitigation tools. The FY 2009 Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-14, and the FY 2009 Section 7(b)(2) Rate Test Study Documentation, WP-07-FS-BPA-14A, detail how BPA proposes to implement the rate test in section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) to ensure that BPA's consumer-owned utility (COU) customers' firm power rates applied to their general requirements are no higher than rates calculated using assumptions specified in the Northwest Power Act.

1.3 Organization

The FY 2009 WPRDS is divided into nine sections.

- Section 1 is this introduction;
- Section 2 discusses rate design changes;
- Section 3 details the cost allocation and rate design implementation;
- Section 4 shows the derivation of inter-business line revenues and expenses;
- Section 5 shows the revenue and purchased power expense forecast;
- Section 6 describes the proposed rate schedules;
- Section 7 covers the application of risk mitigation tools;
- Section 8 describes the ASC and REP load forecast; and
- Section 9 discusses the Slice product and its rate and true-up.

In addition, the FY 2009 WPRDS includes six appendices:

- 7(c)(2) Industrial Margin Study;
- Value of DSI Supplemental Contingency Reserves;
- Generation Market Power Analysis;
- Letter from Mike Weedall on BPA's Final Post-2006 Conservation Program Structure;
- Final Post-2006 Conservation Program Structure – Summary of Key Issues; and
- Final Post-2006 Conservation Program Structure.

Details supporting calculations in data are in the FY 2009 Wholesale Power Rate Development Study Documentation (FY 2009 WPRDS Documentation), WP-07-FS-BPA-13A and WP-07-FS-BPA-13B.

2. RATE DESIGN

This section describes the criteria applied in the development of the rate design. There are a number of rate components used in various combinations depending on products and services negotiated by contract. In general, BPA offers several power and energy rates, including: (1) The Priority Firm Power Rate (PF) consisting of firm energy, firm capacity, or both, and guaranteed by BPA to be available during specific times as outlined by contract for COUs; (2) The Industrial Firm Power Rate (IP), available for contract purchase by BPA's DSI customers; (3) The New Resource Firm Power Rate (NR), available for contract purchase by investor-owned utilities (IOUs) and to COUs for New Large Single Loads; and (4) The Firm Power Products and Services (FPS) rate schedule, which is used primarily for the sale of surplus firm power and related products. In addition to the published rates and charges, this section also describes conservation and General Transfer Agreements (GTAs), among other topics, regarding the rate design process used for this final Supplemental Proposal.

For purposes of establishing the Demand, Energy, and Load Variance rates, this Supplemental Proposal will continue to observe the WP-07 Final Proposal Partial Resolution of Issues. *See* Partial Resolution of Issues, Attachment 1, Administrator's Final Record of Decision, WP-07-A-02, July 2006. The new revenue requirement for FY 2009 will affect these rates. *See* Homenick and Lennox, WP-07-E-BPA-65. Sections 2.3, 2.4, 2.6, 2.8, and 2.11 are the same as those contained in the WP-07 Final Proposal, except that dates and the names of rates have been modified to apply to FY 2009. These sections are provided for convenience. Sections 2.1 and 2.2 have been updated to make them consistent with the Partial Resolution of Issues and the new revenue requirement proposed for FY 2009. *See* FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10. Section 2.5 was modified to limit the discussion to the flexible FPS rate only. The modification reflects that sales under the FPS rate schedule are made only at negotiated prices.

Also, an additional discussion was added to describe a new section of the FPS rate schedule for the reassignment or remarketing of surplus transmission. Section 2.7 has been modified to describe a proposed new methodology used to determine the Priority Firm Exchange rates. Section 2.9 has been modified to reflect a new estimated cost of the LDD due to changes in forecast loads and in the level of the LDD for some customers. Section 2.10 has been modified to remove language concerning certain CRC incremental expenditures. Section 2.12 was modified by replacing references to the "REP settlements" with the "RPSAs." Section 2.13 was modified to acknowledge that Transmission Services has completed its rate proceeding for FY 2008-2009; thus, the GTA Delivery Charge is fixed for FY 2009. Sections 2.14 through 2.19, which appeared in the WP-07 WPRDS, have been moved to other sections of this Study, except for the LB CRAC True-up, which has ended.

2.1 Monthly and Diurnal Differentiation of Energy Rates

In establishing rates for FY 2009, BPA used the same basic approach used in the WP-07 Final Proposal. More specifically, BPA shaped energy rates according the Partial Resolution of Issues. The Partial Resolution of Issues, which details the calculation of the Demand, Load Variance, and HLH and LLH Energy Rates, among other items, is set forth in Attachment 1 of the Administrator's Final Record of Decision, WP-07-A-02, July 2006. All rates are adjusted up or down such that BPA would recover the total revenue requirements necessary to meet its financial obligations, as outlined in the FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10.

2.2 Relationship Between Rate Design and Core Subscription Products

The purpose of this section is to discuss changes in rate design and the relationship of these changes with BPA Core Subscription Products. This section will discuss Demand, Load Factoring, and Load Variance.

2.2.1 Core Subscription Products Principles

BPA Core Subscription Products were developed based on the principle that Core Products are billed from a "common table of rates" to assure equitable comparability of payment among purchasers of different types of Core Products. The common table of rates includes Demand, HLH and LLH Energy Rates, and a Load Variance Rate, where applicable. The common table of rates is associated with a table of billing factors showing the billing determinants appropriate to the specific products. *See* BPA Power Products Catalog, Appendix B, Core Product Billing Factors.

2.2.1.1 Demand Rates for Core Subscription Products

This section describes the construct used in the BPA rate design for Core Subscription Products as discussed in the WP-07 Initial Proposal. However, the Partial Resolution of Issues modified the Demand rate. Therefore, the concept described herein is provided for information only and was not actually used in the calculation of the WP-07 Demand rate.

The purpose of the Demand rate in the Core Subscription Products is to compensate BPA for three components of firm service: (1) the cost of firming bulk energy, including firm energy provided in flat amounts as under the Block product; (2) the cost of service BPA calls "factoring," in which energy is distributed among hours to match a load shape; and (3) the cost of readiness to meet actual load under peak conditions. When combined with energy charges, a Demand rate has the effect of increasing the purchaser's average payment per kilowatt-hour of product, sometimes referred to as the effective rate. If the power delivery is not flat (*i.e.,* peaks during the HLH period), the resulting demand charge plus energy charge makes the effective rate higher than the effective rate of a flat power purchase. To help maintain and assure equitable comparability, the same demand dollar rate ($/kW per month) will be applied to appropriate demand billing factors for different products such as Priority Firm (PF) Full Service, Partial

Service, and Block products, and for any sales made at the Industrial Firm Power (IP) and New Resources (NR) Rate schedules.

2.2.1.2 Development of Demand Rate

BPA continues to propose two energy rates for each month, one for HLH and one for LLH. However, the Market Price Forecast Study (WP-07-FS-BPA-03) demonstrates there is a different market value for power in each hour. To account for the hourly differentials, BPA has developed a Demand rate ($/kW per month) applied in conjunction with the energy rates (mills/kWh).

2.2.1.2.1 Methodology

The methodology used in the design of the monthly Demand rates is no longer applicable due to the Partial Resolution of Issues. *See* Attachment 1 of the Administrator's Final Record of Decision, WP-07-A-02, July 2006. Per the Resolution, the average monthly rate for the WP-07 rate period was modified to equal that of the WP-02 Final Proposal through the following process.

(1) As the starting point, BPA used the average Demand rate of $2.00/kW per month, as specified in the Partial Resolution of Issues, page A-6, Table 1.

(2) The average monthly rate was then shaped in proportion to the average HLH energy as settled in the partial Resolution.

(3) The LLH energy rate was scaled down to reduce total LLH revenues due to the Demand rate increase, which resulted in additional demand revenues, such that total revenues remain the same.

(4) The monthly Demand Rates, the Load Variance Rate, and the HLH and LLH monthly Energy rates were scaled to reflect the revenue requirement in the WP-07 Final Supplemental Proposal, consistent with the Partial Resolution of Issues.

2.2.1.2.2 Results

In the Supplemental Proposal, the final revenue requirement resulted in rates being scaled down, and, therefore, annual average Demand rate is $1.68/kW per month. Monthly Demand rates are stated in the 2007 Wholesale Power Rate Schedules (FY 2009) and 2007 General Rate Schedule Provisions (FY 2009), WP-07-A-05A.

2.2.2 Factoring Service in Core Subscription Products

The term "factoring" is a term of general use in the utility industry. However, for purposes of the Core Subscription Products, it is specifically defined as the BPA service of shaping a given quantity of megawatt-hours among HLH and LLH periods in each month to follow load. In this context, Factoring Service is an "energy-neutral" service. For example, a customer that has a 67 percent load factor (average monthly energy divided by monthly peak) generally would use more Factoring Service than a customer with a 75 percent load factor. A flat or 100 percent load factor purchase uses no Factoring Service. As a customer's load factor percentage drops lower (for example, 57 percent instead of 67 percent), the load shape BPA must serve becomes more extreme, generally requiring more factoring of energy to meet the change in the load factor.

The Factoring Service is a part of both the Full Service and the Actual Partial Service products, as explained below. The amount of Factoring Service taken will be checked in the billing process only for those customers with declared resources with hourly variability, which are dispatchable, and who purchase the Actual Partial (Complex) product or the Block with Factoring product. Customers without resources, or customers whose resources have fixed hourly quantities, take and receive exactly the amount of Factoring Service to which they are entitled. Only when customer resources are dispatchable on a hour-to-hour basis is there a possibility of receiving Factoring Service amounts which are less than or greater than the entitlement amount. In the BPA Power Product Catalog, the product descriptions provide further details on the factoring benchmark calculation. Factoring Service that is within the benchmark will result in no excess Factoring Service penalty charges. The entitled amount of Factoring Service will be paid for at the BPA-posted power Demand Rate applied to the customer's power billing demand.

The Factoring Service is not intended to provide backup or other services for customer resource amounts that are interrupted or otherwise fail to be delivered. If a flat resource fails to be delivered for an hour to a customer within the BPA control area, the power product default treatment is to identify that as an unauthorized increase event. By arrangement, other BPA services could apply, such as an ancillary services acquired by the customer from BPA Transmission Services or a negotiated backup service.

2.2.2.1 Factoring Service as a Staple-On Product and the Appropriate Billing Demand

The BPA Power Product Catalog states that a customer can purchase the Block Product with Factoring Service as a staple-on product. When Factoring Service is added to the Block Product, it provides within-day and within-month factoring of Block energy. This additional service is priced at the Demand rate applied to the appropriate demand billing factor.

2.2.3 The Demand Adjuster

The Demand Adjuster is a billing factor that preserves equitable comparability among customers purchasing different types of core products. Full Service Product customers are billed based on their load on the hour of the Monthly Federal System Peak Load, as they were under WP-02 rate schedules. However, the demand billing factors for the Simple and Complex Actual Partial Service Products and the Block Product with Factoring are based on the customer's system peak load. It is necessary for appropriate product selection and for appropriate customer operation under these products that the demand billing factors for these Partial Service Products be linked to the customer's own system peak. This was the case in the WP-02 Final Proposal for the rates that applied to customers purchasing partial service under the 2001 power sales contracts. However, BPA does not wish to abandon the concept of a common table of rates or to create a lack of equitable comparability. This would be the result if customers were billed at the same dollar rate on different billing demands.

Consistent with the method used in the WP-02 Final Proposal, the Demand Adjuster was developed to resolve this problem by adjusting billing demand kilowatts (kW) to achieve parity with a customer whose billing demand is set on BPA Generation System Peak (GSP). Because a customer's system peak is always equal to or larger than its load on the hour of the Monthly Federal System Peak, this larger billing factor for this type of customer, if not adjusted, would result in lower relative demand billing for the Full Service Product. To maintain a level of comparability, given the different demand billing bases for the products, the Demand Adjuster is used to scale down the Billing Demand of the Actual Partial Service Products and the Block Product with Factoring. The Demand Adjuster is a multiplier consisting of a number less than or equal to one. It is calculated by dividing the customer's Total Retail Load (TRL) on the hour of the Monthly Federal System Peak Load by the customer's TRL on its system peak. The minimum Demand Adjuster is 0.6.

2.2.4 Load Variance Rate

In the context of Core Subscription Products, Load Variance is defined as the variability from forecast of monthly energy consumption within the customer's system. Variability in monthly energy consumption may be caused by weather, economic business cycles, load growth, or load loss. It does not include the variance in load caused by annexation of new load, retail access, or service to New Large Single Loads (NLSL). Such loads will receive Load Variance coverage once the loads are served by BPA under the applicable rate schedule. BPA offers to stand ready to serve the covered variability under the Full Service and Actual Partial Service products. As applied to the Full and Actual Partial Service products, the Load Variance charge allows customers' billing factors to follow actual consumption. This is different for Block products, where the amounts to be paid for are fixed in advance. The Load Variance Rate is set at 0.46 mill/kWh and will be charged based on the customer's TRL. For a discussion of the basis for the calculation of the Load Variance Rate, *see* Section 2.2.4.1.

2.2.4.1 Development of Load Variance Rate

2.2.4.1.1 Methodology

Following the publication of the WP-07 Initial Proposal, the Load Variance Rate was modified through the Partial Resolution of Issues.

2.2.4.1.2 Results

The Load Variance Rate is the sum of the load growth and load variation costs divided by the sum of the billed TRL quantities during the same period. The calculated cost, for the WP-07 Final Proposal, was 0.47 mills/kWh, WP-07-FS-BPA-05A, Table 2.7.1. However, consistent with the Partial Resolution of Issues, the Load Variance rate in this WP-07 Supplemental Proposal is scaled down to 0.46 mill/kWh, along with the Demand and diurnal Energy rates, to a level that satisfied the reduced revenue requirement. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.7. The Load Variance Rate is published in the 2007 Wholesale Power Rate Schedules (FY 2009) and 2007 General Rate Schedule Provisions (FY 2009), WP-07-A-05A, and applies to the PF-07R, IP-07R, and NR-07R rate schedules.

2.3 Operating Reserve Credit

In the WP-07 Supplemental Proposal, the revenue derived from the sale of Operating Reserves to Transmission Services is treated in the same way as in the WP-02 Final Proposal.

2.4 Unauthorized Increase Charges and Excess Factoring Charges

This Supplemental Proposal includes separate penalty charges for Unauthorized Increases in Energy usage; Unauthorized Increases in Demand usage, Excess Within-Day Factoring Energy, and Excess Within-Month Factoring Energy. These charges apply to deliveries that exceed contractual entitlements for demand, energy, and factoring, respectively. Elements common to these penalty charges are described here. BPA also proposes minimum penalty charges for Energy, Demand, and Excess Factoring, with the potential for relevant price indexes to set effective charges for the month at higher levels than the identified minimums. Collectively, market prices reflected by the Dow Jones Mid-Columbia Indexes (DJ Mid-C Indexes) and the California Independent System Operator (CAISO) price indexes provide a basis for the potential opportunity cost (or actual purchase cost) to BPA of serving energy, demand, or factoring in excess of a customer's contractual entitlement. The inclusion of these market price indices in the penalty charge derivations also ensures an appropriate deterrent against customers placing demand, energy, and factoring burdens on the BPA system during periods of high market prices. Where the index-driven prices exceed the specified minimum charges for a given month, they will constitute the effective charges. Examples of these charges are shown in Tables 4.6.1, 4.6.2, 4.6.3, and 4.6.4 of the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A.

There is the possibility that one or more of the currently identified indices for determining the penalty charges will cease to exist during the rate period. The GRSPs account for this possibility by allowing replacement indices, either some index already in existence (*e.g.,* the CAISO) or some other relevant future index available at some point during the rate period. *See* 2007 General Rate Schedule Provisions (FY 2009), WP-07-A-05A, Section II.)

BPA will also provide a reduction in charges associated with single occurrences that trigger multiple penalties. Specifically, there will be reductions to Excess Within-Month Factoring

Charges to the extent that energy in the same diurnal period is assessed the Unauthorized Increase in Energy Charge.

2.4.1 Unauthorized Increases in Energy and Demand

If specified in the applicable rate schedule, the charge for Unauthorized Increase in Energy will be applied for any purchaser taking energy in excess of its contractual entitlement. The charge for a given month will be the highest DJ Mid-C Index price for firm power or the highest CAISO Supplemental Energy price for that month, whichever is greater. The minimum charge will continue to be set at 100 mills/kWh.

The charge for Unauthorized Increase in Demand will be applied to any purchaser taking demand in excess of its contractual entitlement. The minimum charge will be set at three times the monthly Demand Rate from the applicable power rate schedule. The effective charge may be set at a level that exceeds this minimum based on the sum of the hourly CAISO Spinning Reserve Capacity prices during HLH for the month. The sum of hourly Spinning Reserve Capacity prices during all HLH of the month will be compared to the minimum and, if higher than the minimum, will determine the effective Unauthorized Increase Charge for demand. Details on these charges are found in the 2007 General Rate Schedule Provisions (FY 2009), WP-07-A-05A, Section II.Q; and examples from a recent 12-month period can be found in FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 4.6.1 and Table 4.6.2.

2.4.2 Excess Factoring Charges

This Supplemental Proposal includes two separate charges for Excess Factoring: (1) the Excess Within-Day Factoring Charge; and (2) the Excess Within-Month Factoring Charge. The Within-Day factoring test compares the hour-by-hour shape of the customer’s load with the customer’s hour-by-hour energy take from BPA within a day. This test identifies whether or not the hour-by-hour shape of the customer's take from BPA has used more within-day factoring service, measured in kilowatt-hours, than the underlying load would have used. There are separate, but identical, tests for HLH Within-Day Factoring and LLH Within-Day Factoring. For both of these tests, the minimum Excess Factoring Charge for each month will be 5 mills/kWh, although it is likely that the charges may be higher, as defined by hourly CAISO Supplemental Energy prices. For HLH, the highest Within-Day difference during the month between the highest HLH price less the lowest (same day) HLH price, and the 5 mills/kWh minimum, will determine the applicable charge. A corresponding test against the 5 mills/kWh minimum will be applied for LLH difference to determine the LLH Excess Within-Day Factoring Charge.

The sum of the HLH Excess Within-Day Factoring amounts will be billed at the HLH Excess Within-Day Factoring Charge. The sum of the LLH Excess Within-Day Factoring amounts will be billed at the LLH Excess Within-Day Factoring Charge.

The Within-Month Factoring Test compares the day-by-day shape of the customer's load to the customer's day-to-day energy take from BPA within a month. This test identifies whether the day-by-day shape of the customer's take from BPA used more within-month factoring service than the underlying load would have used. The Within-Day factoring test (*see* above) is not equipped to identify a factoring service issue if, for example, a customer's resource deliveries were zero for a particular day. The Within-Month factoring test, however, is equipped to address such an event. The Within-Month factoring test establishes an upper and lower boundary for each diurnal period of the day. Excess Within-Month Factoring for each diurnal period is the greater of: (1) the sum of the megawatt-hours amounts greater than the upper boundary; or (2) the sum of the megawatt-hours amounts less than the lower boundary. There will be a separate quantification of Excess Within-Month Factoring for HLH and of Excess Within Month-Factoring for LLH. The minimum charge for Excess Within-Month Factoring will be 5 mills/kWh. This minimum will be compared with charges derived from the DJ Mid-C Index prices for firm power and the CAISO Supplemental Energy indexes for the month. For HLH Excess Within-Month Factoring Energy, the effective charge will be the greater of: (1) 5 mills/kWh; (2) the difference between the highest DJ Mid-C Index price for firm power among all HLH periods for the month and the lowest HLH DJ Mid-C Index price for firm power; and (3) the difference between the highest average hourly CAISO Supplemental Energy price among all HLH periods for the month and the lowest average hourly CAISO Supplemental Energy HLH price. An equivalent test against the 5 mills/kWh minimum price will be done to determine the effective Excess Within-Month Factoring Charge for LLH.

The Excess Within-Month Factoring energy quantities are reduced by any Unauthorized Increase Energy amounts in the same diurnal period, and only the residual is charged the Excess Within-Month Factoring Charge. Details on these charges are found in the 2007 General Rate Schedule Provisions (FY 2009), WP-07-A-05A, Section II.H; and examples of these charges from a recent 12-month period can be found in the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 4.6.3 and Table 4.6.4.

2.5 Firm Power Products and Services (FPS-07R)

The FPS-07R rate schedule is a flexible rate. This flexible rate is a market-based rate that is negotiable, and it may have a demand component, an energy component, or both. Unbundled products also are available under the FPS-07R rate schedule at flexible rates as mutually agreed by the contracting parties. Applicable transmission rates will apply to the extent required to purchases of firm power under the FPS-07R rate. The West-Wide price Cap as established or approved by FERC will apply to all sales under this rate schedule.

A new Section E is proposed for the final WP-07 Supplemental Proposal. This section is for reassignment or remarketing surplus transmission capacity. This addition will clarify that, consistent with a transmission provider's Open Access Transmission Tariff, Power Services will reassign or remarket surplus transmission capacity at a negotiated or market rate.

Consistent with the Administrator's decision in this proceeding, the flexible FPS rate now includes a Supplemental 7(b)(3) Rate Charge to recover the section 7(b)(2) rate protection allocated to FPS rates pursuant to section 7(b)(3) of the Northwest Power Act. To retain maximum pricing flexibility, the flexible portion of the FPS rate may be negative, if necessary.

2.6 Flexible PF and NR Rate Option

The Flexible PF and NR rate options are offered at BPA's discretion to PF and NR Preference purchasers who purchase under the PF and NR rate schedules and make contractual commitments to purchase under this option. The charges and billing factors under this option are specified by BPA at the time the Administrator offers to make power available to purchasers under this option. The actual charges and billing factors will be mutually agreed to by BPA and the purchasers subject to satisfying the following condition.

- <u>Equivalent Net Present Value Revenues</u>: Forecast revenues from a purchaser under the Flexible PF and NR rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in the appropriate rate schedule been applied to the same sales.

Notwithstanding the effective dates of the PF rate and associated GRSPs, any rights and obligations of BPA and a customer arising out of the customer's election to participate in the Flexible PF Rate Program by purchasing under the Flexible PF Rate option will survive and be fully enforceable until such time as they are fully satisfied. *See* 2007 General Rate Schedule Provisions (FY 2009), WP-07-A-05A, Sections II.I and II.J.

2.7 PF Exchange Rate

The PF Exchange rate applies to the traditional implementation of the REP. This rate is compared with the exchanging utility's Average System Cost (ASC), and the difference is multiplied by the utility's eligible residential and small farm load to determine monetary benefits paid to the utility by BPA. This rate also applies to BPA's actual power sales to exchanging utilities under contractual "in-lieu" transactions. The proposed PF Exchange rate for Energy is not diurnally differentiated. Also, the proposed PF Exchange rate has no Demand rate. The proposed PF Exchange rate has two components: the base PF Exchange rate and a utility-specific Supplemental 7(b)(3) Rate Charge.

2.7.1 Supplemental 7(b)(3) Rate Charge

If the 7(b)(2) rate test triggers the proposed base PF Exchange rate will be adjusted by a utility-specific Supplemental 7(b)(3) Rate Charge. The base PF Exchange rate, so adjusted, will be each utility's aggregate PF Exchange rate and will apply to the exchanging utility's qualifying residential and small farm load in the calculation of REP benefits. For utilities that apply for the REP after a specific date, a Supplemental Charge will be the difference between their ASC and the base PF Exchange rate. The specific date is defined in the proposed ASC Methodology as May 1 in the year prior to a section 7(i) rate proceeding, *i.e.*, 16 months prior to the date new rates would go into effect. *See* BPA's 2008 Average System Cost Methodology Record of Decision issued June 30, 2008. The proposed ASC Methodology defines a Review Period as May 1 through October 1 of the year before BPA implements a change in wholesale power rates. During this Review Period, BPA will determine ASCs for eligible utilities. Those ASCs will then be used in the calculations of power rates in the subsequent rate proceeding, allowing the calculation of the utility-specific Supplemental 7(b)(3) Rate Charges. Without an ASC, BPA cannot compute the utility-specific Supplemental 7(b)(3) Rate Charge.

2.7.2 Components of the Base PF Exchange Rate

The base PF Exchange rate begins with the 7(b) rate pool rate, also known as the unbifurcated PF rate, determined prior to the section 7(b)(2) rate test. This is the precursor to the PF rate, and in the absence of a reallocation of costs resulting from the section 7(b)(2) rate test would be the PF Preference rate. Any reallocation of costs due to the section 7(b)(2) rate test and the 7(b)(2) Industrial Adjustment is added to the PF Exchange rate. A transmission component of $4.26/MWh is in the Base PF Exchange rate.

2.8 Irrigation Rate Mitigation Product

The Irrigation Rate Mitigation Product (IRMP) is a contract-specific rate and not part of the rate design for this Supplemental Proposal. The difference between the forecast revenue between PF rates and the IRMP rates is accounted for as an expense in setting rates. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.5.5.

2.9 Low Density Discount

Section 7(d)(1) of the Northwest Power Act provides that, in order to avoid adverse impacts on retail rates of BPA's purchasers with low system densities, BPA shall apply, to the extent appropriate, discounts to the rate or rates for such purchasers. Such purchasers are utilities with low system densities and with high distribution costs resulting from sparsely populated service areas. The Low Density Discount (LDD) principles, eligibility criteria, and discount reflect the Partial Resolution of Issues (*See* Attachment 1, Administrator's Final Record of Decision, WP-07-A-02, July 2006) and appear in the 2007 General Rate Schedule Provisions (FY 2009), WP-07-A-05A, Section II.L.

The LDD is determined by a formula that computes two ratios. One formula calculates a qualifying utility's ratio of Total Retail Load (TRL) to its depreciated electric plant, excluding generation plant (the Kilowatt-hour/Investment Ratio for LLD or K/I ratio). The other formula calculates the ratio of the number of the utility's consumers to the number of pole miles of distribution lines (the Consumers/Mile or C/M ratio). These ratios are computed with data submitted by the purchaser based on the purchaser's entire electric utility system in the Pacific Northwest (PNW). For purchasers with service territories that include any area outside the PNW, BPA compiles data submitted by the purchaser separately on the portion of the purchaser's system that is in the PNW. BPA applies the eligibility criteria and discount percentages to the purchaser's system within the PNW, and where applicable, also to its entire system inside and outside the PNW. The purchaser's eligibility for the LDD is determined by the lesser amount of discount applicable to its PNW system or to its combined system inside and outside the PNW. BPA, at its sole discretion, may waive the requirement to submit separate data for a purchaser with a small amount of its system outside the PNW.

The discounts under each ratio range from zero to 5 percent, in increments of one-half percent. The discounts from the two ratios are added together to determine the total discount to purchases under an applicable rate. The LDD for any utility is capped at seven percent.

Consistent with the Partial Resolution of Issues for FY 2007-2009, in the WP-07 Final Proposal BPA proposed minor modifications to the 2002 LDD methodology used during FY 2002-2006. *See* Attachment 1, Administrator's Final Record of Decision, WP-07-A-02, July 2006. As during the previous rate period, the discount for any eligible utility will be ramped in from the existing discount. No eligible utility will experience more than a one-half percentage point change (positive or negative) in its LDD beginning October 1, 2006, and each succeeding fiscal year, until the revised LDD percentage is attained. If a utility fails to satisfy the initial eligibility criteria, however, the discount will be zero and will not be ramped in from the existing discount. The Supplemental Proposal is consistent with the Partial Resolution of Issues.

The estimated cost of the LDD is $24.9 million for the FY 2009 rate period. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.5.5.

2.10 Conservation and Renewables Program

BPA will provide financial assistance to its customers to develop conservation projects and renewable resources as part of BPA's wholesale firm power rate design. The Conservation Rate Credit (CRC) is a successor to the Conservation and Renewables Discount (C&RD) and is intended to help implement the program goals set forth in BPA's policy for the development of regional conservation and renewable resources. BPA is looking to its customers and others to be in the vanguard of conservation and renewable resource developments in the region. Both program goals were developed as part of *Bonneville Power Administration's Policy for Power Supply Role for Fiscal Years 2007-2011 (Near-Term Policy)*, and accompanying *Administrator's Record of Decision (Near-Term Policy ROD)*. The Near-Term Policy ROD is available at www.bpa.gov/power/pl/regionaldialogue/02-2005_rod.pdf.

BPA's Near-Term Policy expresses five principles to guide the development of BPA's conservation acquisition programs for post-2006. In brief, these principles are: (1) use the Northwest Power and Conservation Council's plan to identify the regional cost-effective conservation targets upon which BPA's agency share (approximately 40 percent) of cost-effective conservation is based; (2) achieve the bulk of the conservation at the local level; (3) meet BPA's conservation goals at the lowest possible cost to BPA; (4) provide an appropriate level of funding for local administrative support to plan and implement conservation programs; and (5) provide an appropriate level of funding for education, outreach, and low-income weatherization such that these important initiatives complement a complete and effective conservation portfolio. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Appendix F, *Final Post-2006 Conservation Program Structure*. Appendices D and E contain related information.

The structure and program design for the CRC was developed through a collaborative workgroup process. As part of the Near-Term Regional Dialogue, BPA looked to the collaborative workgroup process to assist in developing a fully defined conservation proposal. The collaborative process started in September 2004 and resulted in the post-2006 conservation program structure. *Id.*

BPA's renewable program has changed its focus from large-scale renewable resource acquisition to the facilitation of third-party development of renewable resources. BPA relied on a focus group of regional and customer representatives to guide renewable policy development for the period 2009. During this collaboration, BPA signaled its desire to act in a facilitator role for regional renewable resource development and has included specific facilitation monies in FY 2009 rates for this purpose. BPA's existing long-term renewable resource acquisition costs will be included as FBS system costs along with the forecast costs associated with proposed facilitation activities.

Actual facilitation expenditures will vary somewhat from the budgeted amounts because the facilitation budget partly depends upon Green Energy Premiums (GEPs) and Green Tag (Renewable Energy Certificate) revenues, which will be added to the fixed renewable facilitation budget at the end of each fiscal year. The amount of revenues from GEPs and Green Tags depends on actual market conditions and costs. BPA will review renewable program costs and revenues annually. BPA will use that review to manage total renewable facilitation expenditures to a net cost of $21 million per year. This $21 million serves as a benchmark target for funding the renewable program components and was discussed in the Power Function Review (PFR). BPA's existing long-term renewable resource acquisition costs are included as FBS system costs. *Id.*

2.10.1 Conservation Rate Credit

To encourage its customers to undertake conservation projects and develop renewable resources, BPA is making available the CRC to those who purchase power under the PF-07R (except the PF Exchange rate), NR-07R, and IP-07R rate schedules. The CRC is also available to eligible purchasers of the Slice product. Although the IP-07R rate includes the CRC, BPA forecasts no power sales to DSI customers under the IP rate for the rate period. Therefore, BPA has forecast no DSI participation in the CRC.

To calculate the cost of the CRC, 0.5 mills/kWh was multiplied by the forecast loads served by the eligible rate schedules and the Slice product. The 0.5 mills/kWh rate discount level was originally established in the WP-02 Final Proposal as part of the C&R Discount and is proposed to continue as the CRC for FY 2009. *See* Pyrch, *et al*., WP-07-E-BPA-24, at 5. Customers eligible to receive the CRC will not be required to reduce (*i.e*., require a decrement in) the amount of firm requirements power purchased from BPA. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Appendix F, *Final Post-2006 Conservation Program Structure*. CRC costs are included in the Cost of Service Analysis (COSA) as part of conservation program costs.

Customers' monthly BPA power bills will reflect the CRC as a line item. Individual monthly credits on bills will be 0.5 mills/kWh multiplied by one-twelfth of the customer's forecast annual purchases from BPA under its Subscription contract. For Slice customers, the forecast annual purchase will be based on their contractual percentage share of 7,070 aMW. For non-Slice customers, the forecast annual purchases were based on the forecast of each customer's net requirements as established in the FY 2009 Load Resource Study Documentation, WP-07-FS-BPA-09A, Sections 2.2.1 and 2.2.2. Each customer's expected series of 36 equal monthly line item credits was calculated prior to the FY 2007-2009 rate period. Based on compliance with conservation and renewables implementation guidelines, BPA reserves the right to adjust the specific amount of CRC received by each customer as necessary throughout the rate period. *See* 2007 General Rate Schedule Provisions (FY 2009), WP-07-A-05A, Section II.A.

BPA assumes the CRC will generate no net revenue during the rate period, and that all eligible customers will participate in the CRC. Participation in the CRC program occurs when customers accept the credit on their monthly bills. As participants, customers accept responsibility to make appropriate expenditures in conservation and renewable resources during the rate period as set forth in BPA's Conservation and Renewables Implementation Guidelines, as amended by establishment of the CRC. Customers may also opt out of the CRC program by notifying BPA. Non-participating customers will have the CRC removed from their monthly bills. *Id.*, Section II.A.3.b. Consistent with the terms of the customer's power sales contract with BPA, failure to make the appropriate expenditures will result in the customer reimbursing BPA the difference between the amount of the CRC received and the customer's actual total qualifying expenditures. *Id.*, Section II.A.3.c.

With help from the Northwest Power and Conservation Council Regional Technical Forum (RTF), criteria to determine qualifying expenditures were established to implement the C&R Discount and are continuing for the CRC. After several years of practice, BPA and its customers have experience with hundreds of qualifying expenditures, which may, at times, be reassessed to determine their cost and benefit. For example, BPA may ask the RTF to conduct periodic energy savings performance evaluations at the regional level with appropriate power customer involvement. These evaluations will assist in the determination of future adjustments to the savings credited for measures and program designs in the CRC.

BPA expects the list of cost-effective measures will be updated during the rate period to reflect revised cost-effectiveness standards and to eliminate measures that are not cost-effective. Although all measures must be cost-effective, acceptable measures do not need to be on an approved list to be eligible for the CRC.

A renewable option will be available to customers to facilitate investment in eligible renewable resources. Customers will also be asked to make declarations three months prior to the beginning of the rate period regarding expected levels of conservation and renewable option participation.

Customers participating in the CRC program will also be required to submit reports every six months documenting their individual conservation and renewable resource qualifying expenditures for the period. In these reports, customers must identify the cumulative monetary discounts they have received from the beginning of the rate period to date as well as total qualifying expenditures and qualifying expenditures for the prior six-month period.
A customer not meeting specific targets will be required to prepare an individual customer action plan providing information to demonstrate the customer's ability to achieve sufficient eligible measures to meet its future spending targets. The plan must demonstrate compliance according to a schedule set by BPA. *Id*., Section II.A.3.b.

A final report on qualifying expenditures is required at the end of the customer's discount period. The discount period is the term of the customer's contract or the FY 2009 rate period, whichever is shorter. BPA will evaluate the customer's total conservation and renewable option project qualifying expenditures during the rate period. When documented total qualifying expenditures are less than the sum of the monthly billing credits for the rate period, customers will be required to reimburse BPA for the difference. *Id*., Section II.A.3.d.

BPA will account for the energy savings that are produced through the CRC and from BPA-funded participation in Northwest Energy Efficiency Alliance (NEEA) conservation activities for purposes of achieving the Northwest Power and Conservation Council's conservation target. However, such savings will not be reflected as reductions in the customers' firm net requirement loads during the FY 2009 rate period. Slice and/or Block customers that sign bilateral contracts with BPA obligating the customers to deliver actual energy savings will be required to reduce their firm net requirements loads for the FY 2009 rate period. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Appendix F, *Final Post-2006 Conservation Program Structure*.

BPA reserves the right to inspect and/or audit customers to verify claims of units or completed units of conservation and the ability to monitor or review utility records, verified energy savings method and results, or otherwise review the implementation of conservation programs funded through the CRC program. The number, timing, and extent of such audits shall be at the discretion of BPA. *Id*.

2.10.2 Renewable Option of the Conservation Rate Credit

A Renewable Option is included as part of the CRC program. The total annual renewable energy option cost component of the CRC is limited to $6 million per year and will be included in the renewable program budget. The renewable energy program will reimburse the conservation program annually for renewable claims up to $6 million. A utility customer participating in the Renewable Option is required to declare its total annual eligible renewable resource activities (as prescribed in the CRC implementation manual) at least three months prior to the beginning of each fiscal year of the rate period. This declaration will provide advance notice to BPA so that adjustments can be made to appropriated programs prior to the beginning of the fiscal year. When renewable energy option participation requests in the CRC exceed $6 million annually, participants will be subject to *pro rata* reductions in their renewable option requests so that the $6 million dollar cap is not exceeded. Small utilities (7.5 aMW total loads or less) and all Federal agency customers of BPA are exempt from this reduction in renewable options eligibility.

2.11 Green Energy Premium (GEP)

The GEP is a charge added to applicable rate schedules when a customer chooses to designate any portion (up to 100 percent) of its Subscription purchase as Environmentally Preferred Power (EPP). The GEP applies to customers purchasing firm power under the PF-07R, IP-07R, and NR-07R rate schedules. By paying the GEP, BPA's customers receive EPP and the non-power renewable attributes associated with EPP to meet the needs of environmentally conscious retail consumers. The amount of EPP that customers may designate will be limited by the availability of EPP products and resources and the amount of an individual customer's Subscription firm power purchase. The GEP will range from 0 to 40 mills per kilowatt-hour depending on the specific product or resource types selected by each customer. The negotiated GEP for any specific customer will be calculated by determining costs associated with the EPP product. Such costs to be considered in determining an applicable GEP change may include, but are not limited to, the following: (1) avoided costs of renewable energy credits based on existing BPA resources; (2) avoided costs of renewable energy credits based on new or proposed BPA resources; and (3) endorsement fees for specific EPP resources.

BPA currently forecasts that revenue from Green Tag revenue resulting from sales of Renewable Energy Certificates (RECs) and (from sales of Alternative Renewable Energy (ARE) to Pre-

Subscription power purchasers) will average $1.1 million annually over the rate period. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 3.6.2. BPA has included a matching $1.1 million annual renewable facilitation cost in the renewable program budget for FY 2009. This is a result of BPA's decision to reinvest these revenues in additional renewable activities. *See* Revenue Requirement Study, WP-07-FS-BPA-10, Attachment A.

2.11.1 Conservation Costs

The Northwest Power Act directs BPA to encourage development of conservation and energy efficiency within the PNW. Conservation is defined as a reduction in electric power consumption as a result of increases in the efficiency of energy use, production, or distribution. Conservation must be taken into account when planning to meet the Administrator's obligations to serve loads.

BPA published a decision letter and *Final Post-2006 Conservation Program Structure* on June 28, 2005, outlining the decisions driving conservation targets for the FY 2007-2009 rate period. Acquisition targets for conservation increase to 52 aMW per year. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Appendix F, *Final Post-2006 Conservation Program Structure.* These energy savings are expected to be acquired at an average cost of $1.54 million/aMW, for a total of $80 million. *Id*.

The "conservation" line item (s*ee* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Tables 2.3.1, 2.3.2, and 2.3.3 (COSA 06)) 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 CRC; and (5) a share of the agency's total planned net revenues. The "energy efficiency" revenue line item, seen in Table 2.3.6 (COSA 09), reflects payments provided by other BPA organizations and Federal agencies for the energy efficiency services delivered. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Tables 2.3.1, 2.3.2, and 2.3.3.

2.11.2 Renewable Program Costs

The renewable program includes the following cost components: support costs for core data collection and project development; facilitation costs for facilitation support of customer-developed renewable resources; and Research Design and Development (RD&D) and costs associated with the Renewable Option of the CRC. These net costs average $16 million each year of the rate period. *See* FY 2009 WPRDS Documentation, Tables 2.3.1, 2.3.2, and 2.3.3 (COSA 06), WP-07-FS-BPA-13A. Existing renewable projects that BPA purchases energy from include: 37 percent of Foote Creek I Wind Project, 100 percent of Foote Creek II Wind Project, 100 percent of Foote Creek IV Wind Project, 100 percent of Klondike I Wind Project, 30 percent of Stateline I Wind project, and 100 percent of Condon Wind Project. These projects are expected to produce 51 aMW annually. *See* the FY 2009 Load Resource Study, WP-07-E-BPA-09A, Table A-24. Purchase costs for the output from existing and contracted public purpose renewable resources projects are documented in the FY 2009 WPRDS as part of the Federal system costs. For FY 2009, *see* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Tables 2.3.1, 2.3.2, and 2.3.3 (COSA 06).

2.12 Targeted Adjustment Charge

Under the PF-07R (with the exception of the PF Exchange rate) and NR-07R rate schedules, all customer firm power requests for unexpected additional load service that occur after June 30, 2007, will be subject to a Targeted Adjustment Clause (TAC). The TAC will apply for the duration of the rate period. This includes customers that annex load, new public customers requesting requirements service, and retail access load gain or returning load. The TAC will not apply to amounts of power purchased under a customer's initial Subscription contract. For the subsequent rate period (FY 2010-2011), where such load can be incorporated into the load forecast in the WP-10 rate proceeding, it will qualify for PF rate service.

The TAC will apply to subsequent requests made by a customer under a Subscription contract for requirements service for such customer's load that had been previously served by that customer's own resources as provided under sections 5(b)(1)(A) and (B) of the Northwest Power Act. 16 U.S.C. §§ 839c(b)(1)(A), 839c(b)(1)(B).

BPA may exempt new load from the TAC and apply the PF-07R rate if a public agency customer is annexing or otherwise taking on the obligation of load from another public agency customer in such a manner that BPA's total load obligation does not increase. In this situation, however, the TAC will apply if the annexed requirements load has been previously served by the customer's 5(b)(1)(A) or 5(b)(1)(B) resources because this would increase BPA's total load obligation. BPA may exempt any load from the TAC and offer the otherwise applicable rate if the new load is forecast to be less than 1 aMW per year. In this situation, the Administrator may waive the TAC charge if it is determined to be inconsequential to overall costs.

Where a public agency customer annexes residential and small farm load previously served by an IOU, and such load was receiving REP benefits through the RPSA, the public agency customer will receive, by assignment through BPA, the right to the IOU's REP benefits applicable to the annexed load delivered in an amount of firm power to the annexing public agency customer at the PF-07R rate equal to the amount of REP benefits assigned by the IOU to BPA. Power provided by BPA to the public agency customer to meet the remaining annexed load not covered by the benefits assigned from the IOU will be subject to the TAC.

The TAC will apply for the duration of the customer's contract or through FY 2009, whichever occurs first. If a new public agency customer requests service, the TAC will apply through FY 2009.

For the final Supplemental Proposal, BPA has forecast that no loads will be served under a TAC. However, BPA is including a TAC in order to recover the cost of power purchases that BPA must undertake, if any, to serve unexpected incremental load. The TAC is intended to recover the costs BPA incurs that are not included in BPA's power revenue requirement for FY 2009. If the cost of power to serve these loads is above BPA's embedded costs, BPA's financial reserves may be affected. The TAC will prevent the erosion of reserves that could occur from additional costs to meet unanticipated increases in load.

The TAC is defined as the charge that will apply to the incremental power acquired by BPA that is needed to meet the subject loads. The TAC will be calculated per an individual customer's request and shall be determined in the following manner: BPA will determine the amount of power available to serve incremental requests based on monthly Federal system surplus using critical water conditions, excluding balancing purchases and purchases for System Augmentation as defined in this final Supplemental Proposal, with updates to the final FY 2009 Load Resource Study Documentation, WP-07-FS-BPA-09A, if BPA determines that is necessary. BPA will determine, month by month, available FBS energy that can be used to serve this load. To the extent there is available energy in any month(s), it will be used to serve the TAC load for that month and reduce the total cost of the TAC service.

If sufficient Federal firm power is available to serve the incremental load, such power shall be sold at the PF-07R rate or the NR-07R rate. In the event sufficient Federal firm power is not available and BPA must acquire additional power to meet the load, such additional power shall be sold at the PF-07R rate, or the NR-07R rate, plus a TAC reflecting the difference between the PF-07R rate, or NR-07R rate, and BPA's cost to supply this power.

BPA will calculate the total cost of the additional power for a specific customer request based on BPA's estimated monthly cost to purchase resources at market plus an administrative fee, including any additional incurred costs to serve the incremental load. These additional costs may include, where applicable, transmission, ancillary services, losses, and/or other charges BPA may incur in purchasing power from other entities. The Net Present Value (NPV) of the expected PF or NR revenues will be subtracted from the NPV of the total cost, and the remainder will be levelized across the total megawatt-hours of the incremental load to obtain a levelized mill/kWh charge that will be the TAC rate. That TAC rate will be applied to all energy delivered to the incremental load, even in months where there was sufficient FBS to serve the load.

The TAC rate will not reduce the total price for power below the PF-07R rate or the NR-07R rate, whichever is applicable. The TAC will be applied in addition to the monthly HLH and LLH energy rates, demand rate, and load variance rate for the applicable month or months as specified in the applicable rate schedules.

BPA will calculate the cost basis for a TAC at the time a customer requests power under this schedule. The TAC will be finalized prior to signing a final contract or before initial deliveries of energy, whichever is first.

In order to encourage renewable development in the region, BPA will allow a limited exception to the application of the TAC to customers that buy or develop renewable resources. If a customer is serving a portion of its load with either a certifiable renewable resource eligible for the CRC or a contract purchase of certified renewable resource power eligible for the CRC, for a period less than the FY 2007-2009 rate period, such customer may request additional requirements firm power service during the rate period for such load at the PF-07R rate without being subject to the TAC.

2.13 GTA Delivery Charge

The GTA Delivery Charge is a rate for low-voltage delivery service of Federal power provided under GTAs and other non-Federal transmission service agreements over a third-party transmission system. The GTA Delivery Charge applies to power customers that take delivery at voltages under 34.5 kV, when BPA is paying for the transfer service over the third-party transmission system, unless such costs have otherwise been directly assigned to the specific customer.

Since October 1, 2001, the GTA Delivery Charge has mirrored the Transmission Services' Utility Delivery Charge. The GTA Delivery Charge for FY 2009 continues to be set at the same level as the Utility Delivery Charge, which is $1.119 per kilowatt per month for FY 2009. *See* 2008 Transmission and Ancillary Service Rate Schedules and GRSPs, Section II.A.2. The monthly Billing Factor for the GTA Delivery Charge will be the total amount of Federal power delivered on the hour of the monthly transmission peak load at the low-voltage points of delivery provided for in GTA and other non-Federal transmission service agreements. For the points of delivery that do not have meters capable of determining the demand on the hour of the monthly transmission peak load, the billing factor shall equal the highest hourly demand that occurs during the billing month at the point of delivery multiplied by 0.79.

The revenue associated with the GTA Delivery Charge for FY 2009 is forecast to be $2.3 million**.**

3. COST ALLOCATION AND RATE DESIGN IMPLEMENTATION

3.1 Ratemaking Sequence

BPA's power ratemaking methodology includes a Cost of Service Analysis (COSA), a series of Rate Design Step adjustments, and a Slice Product Separation Step. The COSA assigns responsibility for BPA's power 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, the Rate Analysis Model (RAM), for purposes of calculating BPA's requirements power rates.

3.2 Cost of Service Analysis (COSA)

The COSA allocates the test period power revenue requirement to BPA's customer classes determined in the FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10. The COSA apportions or "allocates" the test period power revenue requirement 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.

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 power and transmission to develop the power revenue requirement; (2) *classification* of costs among demand, energy, and load variance; and (3) *allocation* of costs to classes of service.

In this FY 2009 Proposal, BPA is recalculating FY 2009 power rates to be charged by BPA Power Services in the absence of the FY 2002-2011 IOU REP settlements. Functionalization of costs between power and transmission is performed in conjunction with the development of BPA's total revenue requirements, and only those costs associated with Power Services are included in this FY 2009 Proposal. The one exception is that the gross exchange resource costs are functionalized so that only the power portion is subject to the power cost rate design steps, and the transmission cost 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 portion of the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Section 2.

3.2.1 Power Services 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 U.S.C. § 839e(a)(1).

The FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10, is based on power revenue and cost estimates for a one-year test period, FY 2009. The revenue requirement from the FY 2009 Revenue Requirement Study is adjusted in the FY 2009 WPRDS COSA for projected balancing purchase power costs, system augmentation costs, and the functionalization of REP costs. The adjusted annual functionalized revenue requirement used for rate calculations is shown in the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.1 (COSA 06 FY 2009). The functionalization of REP costs is shown in the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.2 (COSA 07 FY 2009). The total adjusted functionalized revenue requirement for the one-year period is shown in the FY 2009 WPRDS Documentation, WP-07-FS -BPA-13A, Table 2.3.3 (COSA 08).

3.2.1.1 Revenue Requirement Study

In compliance with a Federal Energy Regulatory Commission (FERC) order dated January 27, 1984, *U.S. Department of Energy–Bonneville Power Admin.*, 26 FERC ¶ 61,096 (1984), BPA has prepared a power repayment study specifically for the power function. All costs to be recovered through FCRPS power rates functionalized to power are used to develop the power revenue requirement in this FY 2009 Proposal.

The FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10, also includes demonstrations to show that revenue from proposed rates is adequate to recover all power-related costs of the FCRPS in the rate period and over the repayment period (revised revenue test).

3.2.1.2 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.

3.2.1.2.1 Purchased Power

The purchased power costs reflect the acquisition of power through renewable energy, wind, geo-thermal, and competitive acquisition programs. Costs of purchased power are included in the NR resource pool. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.1 (COSA 06).

3.2.1.2.2 Balancing Power Purchases

The costs of power purchases and storage required to meet firm deficits on a daily and monthly 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 is the expected value over 50 different water conditions. The expense estimate for balancing power purchases included in the revenue requirement is adjusted in the COSA as a result of Risk Analysis Model (RiskMod) modeling to reflect projected operation of the FCRPS. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, 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* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.1 (COSA 06).

3.2.1.2.3 System Augmentation

BPA is also proposing to acquire an amount of resources beyond the inventory represented by the system generating resources and balancing power purchases. These acquisitions are defined as system augmentation costs in the COSA 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. System augmentation costs are shown in the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.1 (COSA 06).

3.2.2 Functionalization 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 and transmission services associated with serving exchanging utilities' exchangeable loads. The rate design adjustments that follow the COSA in BPA's ratemaking use the results of the COSA on that portion of the revenue requirement that has been functionalized to power. Therefore, because the REP cost that is used in the COSA includes energy costs, demand costs, and transmission costs, these costs are functionalized between power and transmission. The REP costs functionalized to power continue through the ratemaking process, and the REP costs functionalized to transmission are added to the PF Exchange rate after all the rate design steps have been accomplished. In this way, the REP costs functionalized to power 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 FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.2 (COSA 07).

3.2.3 Classification

Classification in the FY 2009 WPRDS apportions power costs between the demand, energy, and load variance components of electric power. This classification of the power revenue requirement is shown in the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.3 (COSA 08).

The classification methodology BPA uses is generally based on the marginal costs of the components of power and generally accepted ratemaking procedures. In this rate filing, the Demand Rate is based on a Partial Resolution of Issues, as it was in the WP-07 Final Proposal. A description of the Demand Rate methodology is in section 2.2.1.2.1 of the WP-07 WPRDS, WP-07-E-BPA-05A. In addition, BPA estimates the Load Variance Rate using market prices. *See* section 2.2.4.1 of the WP-07 WPRDS, WP-07-E-BPA-05, for a detailed description. The Load Variance Rate is scaled in accordance with the Partial Resolution of Issues. Sales and revenues of these products are then forecast. Revenues forecast for demand are deemed equal to the cost of providing demand services and are classified to the demand component of electric power. Revenues forecast for Load Variance are deemed to be equal to the cost of Load Variance and are classified as such. Power costs classified to energy are the residual total power costs not classified to demand or load variance. BPA continues this classification scheme in this FY 2009 Proposal; however, the costs of demand and load variance are now directly allocated to customer rate pools along with the costs of energy. After all allocation and rate design steps, the costs of demand and load variance are subtracted from the overall costs allocated to each rate pool, and the energy rates are adjusted to collect the remainder.

3.2.4 Functionalized and Classified Revenue Credits

The revenue credits described below are functionalized to power 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.

3.2.4.1 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 COE and Reclamation for benefits received (*i.e.,* additional generation) from the storage reservoirs owned by the COE 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 rates and hence become revenue credits. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Section 2.3.4 (COSA 09).

3.2.4.2 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 operational 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 completed. The operational costs vary with water conditions. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.4 (COSA 09).

3.2.4.3 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* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.4 (COSA 09).

3.2.4.4 Energy Efficiency Revenues

This credit involves revenues associated with the activities of BPA's Energy Services Business. These revenues are allocated as an offset to BPA's conservation expenses and reduce the amount of those expenses allocated to power rates. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.5 (COSA 09A).

3.2.4.5 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 rates. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.4 (COSA 09).

3.2.4.6 Reserve Product Revenues

Reserve product revenues result from the sale of products and services provided under the FPS rate schedule to customers outside the BPA Control Area and may include supplemental automatic generation control, spinning reserves, supplemental reserves, and forced outage reserves. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.4 (COSA 09).

3.2.4.7 Green Tag Revenues

Green energy premiums (GEPs) result from BPA sales of Environmentally Preferred Power (EPP) and renewable energy certificates. The revenue amounts depend on actual wind and renewable project output included in the FBS. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.4 (COSA 09).

3.2.4.8 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. *See* Section 4 of this Study. The revenues and credits are classified to energy and have the effect of reducing the FBS resource costs to be recovered by BPA's power rates. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.4 (COSA 09).

3.2.5 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 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. The sizes of the rate and resource pools are determined from forecast load and resources prepared in the FY 2009 Load Resource Study, WP-07-FS-BPA-09.

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 power BPA sells in the PNW. 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.

In BPA's WP-07 Supplemental rate filing, 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* FY 2009 Revenue Requirement Study Documentation, WP-07-FS-BPA-10A or WP-07-FS-BPA-10B. 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.

3.2.5.1 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 FY 2009 Load Resource Study, WP-07-FS-BPA-09, 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 2.4.1 (ALLOCATE 01) shows the ratemaking energy loads and resources by pools. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.4.1 (ALLOCATE 01).

3.2.5.2 Energy Allocation Factors

When service from each resource pool to each class of service has been identified, the amounts of such service is the allocation factor 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 FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.4.1 (ALLOCATE 01). The Total Usage and Conservation allocation factors are the same and are based on the sum of the FBS, Exchange, and NR allocation factors. They are used to allocate costs and rate design adjustments to all firm energy loads. Allocated power costs are shown in the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.4.2 (ALLOCATE 02).

3.2.5.3 Other Cost Allocations

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

3.2.5.3.1 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. § 839a(19). The "conservation" line item, as seen in the COSA 06 tables (*see* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.1), 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 2.3.5 (COSA 09A) reflects payments provided by other BPA organizations and Federal agencies for the energy efficiency services delivered. Energy Efficiency revenues are credited against BPA's conservation costs, and the conservation costs that are net of these revenues continue though the remaining ratemaking process. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.5 (COSA 09A).

3.2.5.3.2 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 power portion of these program costs is determined in the FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10. The power portion appears as BPA program costs. These program costs, as seen in Table 2.3.3 (COSA 08), are allocated uniformly to all customer classes based on the total usage allocation factors for energy. S*ee* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.3 (COSA 08). A deemer credit that represents an amount of an exchanging utility's deemer balance that is forecast to be paid down in FY 2009 is credited against BPA's program costs, and the program costs that are net of this adjustment continue through the remaining ratemaking process. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.3.6 (COSA 09B).

3.2.5.3.3 Planned Net Revenues for Risk (PNRR)

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 Power Services' portion of Treasury payments on time and in full. PNRR are allocated to resource pools that include Federal capital investments. The PNRR value for this FY 2009 Proposal has been determined to be zero. Had the PNRR value not been zero, it would have been found in the COSA 06 tables and would have been the result of an iterative process between the RAM2007, the RiskMod, Non-Operating Risk Model (NORM), and the ToolKit models. *See* FY 2009 Risk Analysis Study, WP-07-FS-BPA-12. 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. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A. For further explanation of this iterative process, *see* Doubleday, *et al.*, WP-07-E-BPA-15.

3.2.6 COSA Results

The COSA results are allocated to the test period revenue requirements for power to classes of service served with firm power. Table 2.4.2 (ALLOCATE 02) summarizes the allocated power revenue requirement and the total allocated revenue requirement recovered from power classes of service. This includes transmission costs allocated to the Power Services. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.4.2 (ALLOCATE 02).

3.3 Rate Design Step Adjustments

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

3.3.1 Secondary and Other Revenue

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

3.3.1.1 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. BPA projects secondary energy sales and revenues using 50 historical water years as determined in RiskMod. *See* Russell, *et al.,* WP-07-E-BPA-67. 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. *See* FY 2009 Risk Analysis Study, WP-07-FS-BPA-12. BPA expects to generate secondary energy that will produce about $774.2 million in revenues in FY 2009. Of the total $774.2 million in forecast secondary revenue, $205.3 million is allocated to the section 7(b)(3) supplemental rate charge associated with the calculated 7(b)(2) rate test trigger. The remaining $568.9 million is allocated as a revenue credit to the unbifurcated PF rate. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.5.3 (RDS 11). In one of the last ratemaking steps, the Slice Separation Step, 22.63 percent of the total $774.2 million in forecast secondary revenue (about $175.2 million) will be sold to BPA's Slice product customers, producing no incremental revenue. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.6.1 (SLICESEP 01).

3.3.1.2 Other Revenue Credits

BPA receives revenue from miscellaneous sources and from miscellaneous power sales. These sources include reimbursements from the U.S. Treasury for section 4(h)(10)(C) credits, *see* FY 2009 Risk Analysis Study, WP-07-FS-BPA-12, Section 2.4.11, and for Colville settlement payments, *id.*, Section 2.5.3.3. Other sources include ancillary product revenues from Transmission Services, reimbursable energy efficiency expenses, and USBR pumping power sales. For FY 2009, the forecast revenue from these sources is $193.1 million. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.5.3 (RDS 11).

3.3.1.3 Allocation of Other Revenue Credits

Other Revenue Credits are functionalized to power and classified to energy. They are then allocated to loads served with Federal Base System resources (FBS) and conservation, in the case of reimbursed energy efficiency expenses. The power-related revenues are allocated in this manner because they are associated with the use of FBS resources to serve the firm contract sales. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.5.3 (RDS 11).

3.3.2 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 2009 rate period, it will receive $124.3 million in revenues from the sale of firm power in various PNW and Southwest markets. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.5.4 (RDS 17). BPA has allocated $325.1 million in power costs to the firm power. Therefore, there is a revenue deficiency of $200.8 billion over the one-year test period. This revenue deficiency is charged to all firm power

(PF, IP, NR) rates. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.5.4 (RDS 17).

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 LDD and 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* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.5.5 (RDS 19).

3.3.3 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 rates to DSI customers 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 IP rate is to be based on BPA's "applicable wholesale rates" to its COU customers plus the "typical margins" included by those customers in their retail industrial rates. Section 7(c)(3) provides that the IP rate is 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 this FY 2009 Proposal, BPA is proposing no uniform SCRA credit to be applied against DSI rates. Thus, the IP rate is 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 3.3.4. and 3.3.5 below for additional explanation.

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 the overhead costs that COUs 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 Appendix A. The net margin is 0.573 mills/kWh and has not been changed from the WP-07 Final Proposal. As previously stated, no SCRA credit is assumed in this FY 2009 Proposal. The net margin is added to the seasonal and diurnal PF energy charges. These adjusted energy charges and the charge for demand are applied to the DSI test period billing determinants to determine the initial IP rate.

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. However, the allocation of the 7(c)(2) delta changes the PF rate upon which the IP rate is based. The interaction between the PF rate and the IP rate has been reduced to an algebraic solution. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.5.6 (RDS 21).

BPA does not expect to sell power under the IP rate schedule in FY 2009. In order to calculate an IP rate in the case where there is no actual load, a token load of 0.0001 aMW was used. Therefore, the size of the 7(c)(2) delta for the one-year test period is very small and has an inconsequential effect on non-IP rates. However, the calculation is shown for continuity of methodology purposes, and to establish a properly calculated IP rate should a qualifying purchaser request service.

3.3.4 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, which receives the rate protection, and PF Exchange rate, which does not receive rate protection and bears its allocated share of the rate protection reallocation. The rate protection amount is collected though section 7(b)(3) Supplemental Rate Charges applied to all non-PF Preference sales. A further calculation is performed to determine utility-specific Supplemental 7(b)(3) Rate Charges for the utilities participating in the REP. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.9 (REP 1).

The FY 2009 Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-14, indicates the 7(b)(2) rate test has triggered, and the PF rate applicable to BPA's COU 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 COU customers and reallocate 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 FY 2009 Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-14. In the FY 2009 Proposal for FY 2009, the rate protection amounts to 8.2 mills/kWh, or a reduction of about $517.6 million to the allocated costs for the PF Preference customer class. This protection is reallocated to the remaining power customers. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.5.9 (RDS 30).

3.3.5 7(b)(2) Industrial Adjustment

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 FY 2009, BPA has used a very small token amount of load for ratemaking purposes. Therefore, the amount of the new 7(c)(2) delta is nearly zero. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.5.10 (RDS 33).

3.3.6 REP Deemer Adjustment

If, in this FY 2009 Proposal, BPA had forecast that an exchanging utility was in deemer status, a third adjustment would have been necessary to allocate an increase in the gross REP costs resulting from the increase of the PF Exchange rate resulting from the reallocation of the 7(b)(2) rate protection. A utility in deemer status has its lower ASC deemed equal to the PF Exchange rate. Gross exchange costs were calculated prior to the 7(b)(2) rate test at the lower PF Exchange rate. Now, with the higher PF Exchange rate, its ASC is higher than before the reallocation of the rate protection. Therefore, gross exchange costs must be recalculated due to the higher ASC for the deeming utility. In that case, any increase in the gross exchange costs can be allocated only to the PF Exchange rate and the NR rate. Because BPA has forecast no utilities in deemer status, this rate adjustment is not necessary in this FY 2009 Proposal.

3.3.7 DSI Floor Rate Test

Section 7(c)(2) of the Northwest Power Act requires that the rates to DSI customers 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 test is performed to determine if the proposed IP rate is 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.

The first step in calculating the floor rate is to apply the IP-83 Standard rate components to test period (FY 2009) DSI billing determinants. Although the energy billing determinants used for this calculation are easily derived from the energy billing determinants for the proposed rates, the demand billing determinants are different. The IP-83 Demand rates were 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 then reduced by an Exchange Cost Adjustment and a Deferral Adjustment that were included in the IP-83 rate, but are no longer applicable. 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 IP-83 rate in the same manner that the Exchange Cost Adjustment and Deferral Adjustment 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 proposed IP rate. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Tables 2.5.7 (RDS 23) and 2.5.8 (RDS 24), for the DSI floor rate calculation. With no DSI floor adjustment required, the final Rate Design Step allocations are shown in RDS 33 of the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.5.10.

3.4 Slice Cost Calculation

Slice customers assume the obligation to pay a percentage of BPA's costs, rather than pay a pre-determined rate per kilowatt or kilowatt-hour. 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 Services revenue requirement identified in this FY 2009, Proposal with certain limited exceptions. For the calculation of the cost of the Slice product for FY 2009 in dollars per month for each percent of the Federal system, *see* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.13 (Slice Cost Table). Note that the cost per month for each percent of the Federal system of about $1.919 million on the FY 2009 Slice Cost Table is the calculated amount for FY 2009 only and that the actual Slice product cost charged in FY 2009 will be the three-year average (FY 2007 though FY 2009), or about $1.873 million per percent per month.

3.5 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 recovered from the remaining non-Slice PF Preference load through the PF Preference Energy, Demand, and Load Variance rates. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.6.2 (SLICESEP 01).

3.5.1 Non-Slice PF 7(c)(2) IP Rate Adjustment

After the Slice PF Product Separation Step, the PF Preference rate level may have changed, necessitating a third 7(c)(2) IP-PF link adjustment. This rate adjustment sets the final IP rate equal to the non-Slice PF rate at the DSI load factor, plus the industrial margin, plus any Supplemental 7(b)(3) Rate Charge. Because there is no IP load forecast for FY 2009, BPA has used a very small token amount of load for ratemaking purposes. Therefore, the amount of the new 7(c)(2) delta is nearly zero. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.6.2 (SLICESEP 02).

3.6 Rate Analysis Results

The rate modeling described above results in an average PF-07R Preference rate of 26.90 mills/kWh, an average IP-07R rate of 34.82 mills/kWh, an average NR-07R rate of 68.45 mills/kWh, and a load-weighted average utility –specific PF Exchange rate of 47.54 mills/kWh. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 2.7, Table 2.10, Table 2.11, and Table 2.9A.

4. INTER-BUSINESS LINE REVENUES AND EXPENSES

This section explains changes in the inter-business line revenues and expenses between BPA's Power Services and Transmission Services (Generation Inputs). Power Services is compensated through a Memorandum of Agreement for the generation inputs Power Services provides to Transmission Services for the provision of ancillary services sold to transmission contract holders. The Generation Inputs costs that were developed in the WP-07 Final Proposal were used by Transmission Services to set its transmission and ancillary services rates for FY 2008 and FY 2009. These rates were part of the rate settlement of the TR-08 rate proceeding and will not be affected by anything in this Supplemental Proposal. Section 4.1 describes forecast changes that will be incorporated in the FY 2009 Power Services revenue forecast. These forecast changes are based on information updates that have occurred since the WP-07 rates were finalized. These forecast updates include changes to the Generation Inputs of Operating Reserves, Regulating Reserves, and Generation Supplied Reactive. For the FY 2009 revenue forecast, the net change is $16.590 million more revenue than the WP-07 Final Proposal. These forecast updates are based on changes to quantities of Generation Inputs needed by Transmission Services and the outcome of a recent FERC proceeding. These forecast changes are shown in Table 4.4. The underlying methodologies that were used in the WP-07 Final Proposal to price the Generation Inputs have not been changed. These underlying methodologies, other study information, and the associated tables from the WP-07 Final Proposal are included in Sections 4.2 through 4.4 and Tables 4.4.1 through 4.5.3 for informational purposes only.

4.1 Generation Input Forecast Changes for FY 2009

In the WP-07 Final Proposal, FY 2009 revenue from Operating Reserves – Spinning and Supplemental was estimated to be $25.673 million based on a need of 380 MW at a per-unit price of $5.63/kW. The per-unit price was determined in the Partial Resolution of Issues.

See Appendix 1. The revised forecast is $31.551 million based on a forecast need of 467 MW at a per-unit price of $5.63/kW. The revised forecast is based on the FY 2008 amount of operating reserves requested by Transmission Services.

In the WP-07 Final Proposal, FY 2009 revenue for Generation Supplied Reactive and Voltage Control was estimated to be $12,500,000 based on the uncertainty of the outcome of a Federal Power Act section 206 proceeding at FERC challenging Generation Supplied Reactive and Voltage Control rates of non-Federal power producers. That proceeding resulted in the elimination of Transmission Services payments for inside-the-band Generation Supplied Reactive and Voltage Control for all generators in the BPA balancing area. As a result, the revised forecast is $4.091 million, which is based solely on synchronous condenser costs. The FY 2009 costs for the synchronous condensers are set in a Memorandum of Agreement between the business lines at $4,091,096 per year.

Pursuant to the Wind Integration Rate Case Settlement, Power Services will supply generation inputs for the new Transmission Services' control area service called "within-hour balancing service for wind generation" in FY2009. Staff's initial proposal forecast of $14.031 million was revised to $19,124,320 for the WP-07 Supplemental Final Study based on the outcome of the Wind Integration Rate Case Settlement.

4.2 Generation Inputs for Ancillary Services (for informational purposes only)

The generation inputs for ancillary services covered in this section include Operating Reserves, Regulating Reserves, and Generation Supplied Reactive. For each of these generation inputs for ancillary services the following sections describe the methodology, identify the assumptions used in the methodology, and establish the generation input rate and up-to rates that are applied to determine the annual revenue forecast for each generation input.

4.2.1 Operating Reserves

Operating Reserves are defined by the Western Electricity Coordinating Council (WECC) as the reserve generating capacity (or rights to interrupt delivery of generation) necessary to allow an electric system to recover from generation failures. Operating Reserves are the unloaded generating capacity, interruptible load, or other on-demand rights that the control area is able to fully deploy within 10 minutes of a power system disturbance and that are capable of being used to serve load on a sustained basis for up to one hour. Operating Reserves include both Spinning Reserves and Supplemental (Non-Spinning) Reserves. The WECC Minimum Operating Reliability Criteria (MORC) provisions were developed with the intent to provide secure and reliable operation of the bulk electric systems in the Western Interconnection. MORC provisions cover, among other things, generator operation and performance that include requirements for Operating Reserves. Specifically, WECC MORC requires that each control area participating in a power pool shall maintain an Operating Reserves equal to at least the sum of 5 percent of all hydro, 5 percent of all wind, and 7 percent of all thermal and other online generation within the control area.

The *pro forma* tariff allows transmission customers the option of procuring their Operating Reserves, either by (1) self-supply, (2) purchase from a third-party supplier, or (3) purchase from the transmission provider. In the BPA control area, transmission contract holders are allowed, pursuant to the *TBL Business Practice for Operating Reserves* to switch suppliers to meet their entire reserve obligation to the control area. As the control area operator, Transmission Services must provide Operating Reserves to any transmission customer that does not self-supply or third-party supply. In these instances, Transmission Services acquires the generation inputs for these Operating Reserves from Power Services.

4.2.1.1 Spinning Reserves

Spinning Reserves, a part of Operating Reserves, are the unloaded generating capacity of a system's firm resources that are synchronized to the power system. Spinning Reserves provide additional energy as required to be immediately responsive to system frequency. WECC currently requires that each control area maintain Spinning Reserves equal to a minimum of 50 percent of its Operating Reserves obligation.

4.2.1.2 Supplemental Reserves

Supplemental Reserves are that portion of the Operating Reserves that does not meet the definition of Spinning Reserve. Supplemental Reserve is that portion of Operating Reserves capable of serving load on a sustained basis within 10 minutes. WECC requires that each control area maintain Supplemental Reserves equal to a minimum of its Operating Reserves obligation minus its Spinning Reserves.

4.2.1.3 General Methodology

The methodology used to establish the up to generation input cost for Operating Reserves is developed by calculating the unit cost of all FCRPS hydro projects in the BPA control area including fish and wildlife, generation integration (GI), and step-up transformer costs. This methodology excludes the costs of CGS, non-performing assets, conservation, and the REP. Revenues from the generation input for Generation Supplied Reactive are subtracted from the FCRPS hydro cost before calculating the unit cost for the Operating Reserves generation input. This adjusted FCRPS hydro cost is divided by the average hydro system uses to determine the embedded unit cost. This unit cost is used to calculate an annual revenue forecast for Operating Reserves. The Partial Resolution of Issues between BPA and rate case parties was reached regarding the generation input cost of operating reserves. In the Partial Resolution of Issues BPA agreed to set the per unit rate for operating reserves at the same level as in the FY 2002-2006 power rate period. *See* Section 2.3, Operating Reserves Credit.

4.2.1.4 Calculation of Unit Cost of Operating Reserves Generation Input

To calculate the unit cost of Operating Reserves, BPA determined the average annual cost of all FCRPS hydro projects based on the embedded costs of hydro, less forecast Generation Supplied Reactive for FY 2009, to be $771 million. *See* WPRDS Documentation, WP-07-FS-BPA-13A.

Second, BPA forecast the average system use (9,217 MW generation, plus 380 MW Spinning and Supplemental Operating Reserve obligation, plus 350 MW Regulating Reserve obligation) to be 9,947 MW. *See* WPRDS Documentation, WP-07-FS-BPA-13A. Third, BPA calculated 3.8 percent based on the proportion of the Operating Reserve Obligation to the average hydro system uses. This percentage was multiplied by the power revenue requirement to determine the adjusted power revenue requirement of $29 million per year that reflects generation input costs provided for Operating Reserve. Finally, PBL determined the per-unit generation input rate for Operating Reserve by dividing the adjusted power revenue requirement of $29 million by the total Power Services Operating Reserve Obligation (380 MW × 12 months × 1000) to yield $6.46 kW per month per unit cost.

4.2.2 Assumptions

The following assumptions are used in the calculation of the unit cost of Operating Reserves generation input and, subsequently, the development of an annual Power Services revenue forecast for the provision of Operating Reserves in the BPA control area:

(1) Total BPA Control Area Reserve Obligation	690 MW
(2) Total Self-Supply or Third Party Reserve Obligation	310 MW
(3) Total Power Services Reserve Obligation	380 MW
(4) Total BPA Control Area Regulating Reserve Obligation	350 MW

4.2.3 PBL Revenue Forecast for Operating Reserves Generation Input

The assumptions in Section 4.1.2 coupled with the WP-02 generation input rate of $5.63 kW per month are applied to calculate an adjusted annual revenue forecast of $25 million for the generation inputs provided to Transmission Services for provision of Operating Reserves, net of self-supply and third-party supply. The calculation for the adjusted revenue forecast takes Power Services' Reserve Obligation multiplied by a rate of $5.63 kW per month, multiplied by 12 months, multiplied by 1,000.

4.2.4 Regulating Reserves

This section describes the method BPA used to allocate costs to the Regulating Reserves generation input.

4.2.4.1 Description of Regulating Reserves

Regulating Reserves are produced by the generating capacity of a power system that is immediately responsive to Automatic Generation Control (AGC) signals without human intervention and is sufficient to provide normal regulating margin. Regulating Reserves are required to provide AGC response to load and generation fluctuations in an effective manner. In order to maintain desired compliance with the North American Electric Reliability Council (NERC) AGC Control Performance Standards (CPS) criteria, Transmission Services currently estimates this minimum requirement to be an annual average of 350 MW.

4.2.4.2 General Methodology

The methodology used to establish the up to generation input cost for Regulating Reserves is developed by calculating the unit cost of the Big 10 FCRPS hydro projects, plus an AGC adder to account for lost efficiency and increased operation and maintenance (O&M) costs due to the provision of this service. Regulating Reserves may be provided by any of the Big 10 plants, and therefore, the cost of this service is based upon the costs of these plants. The cost of the FCRPS

Big 10 plants includes a share of the fish and wildlife cost and associated GI and step-up transformers costs. This methodology excludes all other hydro assets, CGS, non-performing assets, conservation, and the REP. Generation-Supplied Reactive generation input revenues are subtracted from the Big 10 cost before calculating the unit cost for the Regulating Reserve generation input.

4.2.4.3 AGC Adder Calculation

The AGC adder calculation includes the analysis of efficiency loss cost, increased O&M costs, and the determination of a multiplier. The calculation combines all of these together to determine the cost for providing this service in addition to the unit cost of the Big 10 FCRPS hydro projects.

4.2.4.4 Efficiency Loss Cost

To analyze the efficiency loss due to AGC, BPA used load efficiency curves for typical Francis units (the type of generators at Grand Coulee and Chief Joseph) and typical Kaplan units (the type of generators on the lower Columbia and Snake Rivers). *See* WPRDS Documentation, WP-07-FS-BPA-13A. The load efficiency curves tell how efficient the turbines are when producing a specific amount of MW at a specific head. The curves generally peak at one generation point and then decrease as the generation moves away from that point of maximum efficiency. Consistent with the WP-07 Final Proposal, BPA modeled the decrease in efficiency due to operating the units away from the most efficient point along the unit efficiency curve. BPA analyzed the shape of the load efficiency curves and estimated the percent efficiency loss at midpoint of the downside and upside points of peak efficiency. For modeling purposes, BPA assumed the upside and downside generation levels were governed by points corresponding to limits of the 1 percent operating range. If the efficiency curve was a straight line instead of a rounded curve, the efficiency loss would average about 0.5 percent. The efficiency loss was calculated as 0.25 percent for Kaplan units and 0.29 percent for Francis units. The lost efficiency is multiplied by the number of hours operated and the average price of energy. *See* WPRDS Documentation, WP-07-FS-BPA-13A.

4.2.4.5 Increased O&M Costs

The cost of maintaining the Big 10 plants was calculated and divided by the generating capacity at normal operation to determine a base value of O&M cost per kilowatt. Interviews taken previously from the O&M staff at Bonneville, Grand Coulee, and the lower Snake River Dams for the WP-02 Final Proposal were used to determine an estimated increase in O&M costs due to AGC operation. *See* WPRDS, WP-02-FS-BPA-05, at 76. BPA multiplied the base O&M cost times this percentage to determine the increased O&M charges per kilowatt. *See* WPRDS Documentation, WP-07-FS-BPA-13A.

4.2.4.6 Multiplier

The multiplier is used to determine how many generating hydro units must be online to provide the required amount of AGC. Each generating unit has operational constraints that require that unit to operate between low and high generating boundaries. To provide the required amount of AGC, a generating unit must be generating at a level that will allow the unit to respond to the AGC signal by decreasing or increasing generation and still be able to operate the unit within normal operational boundaries. The boundaries in this case were determined to be within 1 percent of peak efficiency. For example, if a 100 MW unit is operated at 70 MW for peak efficiency and the lower and upper boundaries for the 1 percent limit are 60 MW and 80 MW respectively, then the range is plus or minus 10 MW. This is the maximum amount of AGC that can be counted on from this unit. This means the actual megawatts of AGC required must be multiplied when considering effects on the generating units. In the foregoing example the multiplier would be 7 (70 MW ÷ 10 MW). To calculate the multiplier, unit efficiency curves for

Grand Coulee, Chief Joseph, and Bonneville Dams were analyzed. The multiplier was calculated by dividing the amount of megawatts at peak efficiency by the smaller of the plus or minus generation range. Each separate multiplier is then weighted by the corresponding number of megawatts for each unit. The efficiency and O&M costs for both are multiplied by the weighted multiplier. After determining the cost for AGC provided by both Kaplan and Francis units, the portion of AGC provided by each is determined and combined to determine a composite rate. *See* WPRDS Documentation, WP-07-FS-BPA-13A.

4.2.4.7 Calculation of Unit Cost of Regulating Reserve Generation Input

BPA calculated the average annual cost of the Big 10 FCRPS hydro projects less generation supplied reactive revenue to be $670 million. *See* WPRDS Documentation, WP-07-FS-BPA-13A. The forecast average system use for the Big 10 (generation, Spinning and Supplemental Operating Reserve obligation, and the Regulating Reserve obligation) is 8,927 MW. *See* WPRDS Documentation, WP-07-FS-BPA-13A. System uses that are provided by all FCRPS hydro projects (generation, Spinning and Supplemental Operating Reserve obligations) are multiplied by 89 percent to determine the Big 10 share of the obligation. The BPA Control Area Regulating reserve obligation that is provided by the Big 10 hydro projects is forecast to be a minimum of 350 MW. Of this amount, the Transmission Services share is estimated to be 150 MW, and the remaining 200 MW is capacity available to meet load following needs for BPA requirements customers. The per unit base charge of $5.76/kW per month is calculated using the average system use (generation, Spinning and Supplemental Operating Reserve obligations, as well as the Regulating Reserve obligation) divided into the revenue requirement. The revenue requirement for Regulating Reserve is found by multiplying the revenue requirement by the ratio of the Regulating Reserve obligation to the total average system uses. The up to Generation Input charge of $7.31/kW per month equals the Big 10 base cost of \$5.76/kW per month plus the AGC Adder of \$1.55/kW per month. *See* WPRDS Documentation, WP-07-FS-BPA-13A.

4.2.4.8 Assumptions

The following assumptions are used in the calculation of the unit cost of Regulating Reserve generation inputs and subsequently the development of an annual PBL revenue forecast for Regulating Reserves.

(1) Total BPA Control Area Reserve Obligation	690 MW
(2) Total Self-Supply or Third Party Reserve Obligation	310 MW
(3) Total Power Services Reserve Obligation	380 MW
(4) Total BPA Control Area Regulating Reserve Obligation	350 MW
(5) Total Transmission Services Regulating Reserve Obligation	150 MW

4.2.4.9 Power Services Revenue Forecast for Regulating Reserves Generation Input

Power Services applied the assumptions in Section 4.2.4.8 to develop an up to generation input cost for Regulating Reserves that consequently will establish the annual revenue forecast. The result of this calculation is \$7.31/kW per month. The base generation input charge is calculated from the adjusted power revenue requirement, for the Big 10 hydro projects, of \$26,273,284 divided by the Power Services reserve obligation (380 MW × 12 months × 1,000) = \$5.76/kW per month plus the AGC Adder of \$1.55/kW per month. The annual revenue forecast for Regulating Reserves is determined to be \$13,161,033. This forecast is calculated by the total Transmission Services Regulating Reserve obligation of 150 MW multiplied by the per unit rate (\$7.31/kW per month × 12 months ×1,000).

4.2.5 Generation Supplied Reactive and Voltage Control

This section describes the method BPA used to allocate power costs to the generation input cost for generation supplied reactive power and voltage control for FY 2009. Also described below is BPA's proposal to remove inside the band compensation and to estimate a forecast of outside the band compensation for generation supplied reactive power effective FY 2008-2009. *See* Bermejo, *et al.*, WP-07-E-BPA-20; Reactive Power Study, WP-07-E-BPA-29; and Reactive Power testimony, WP-07-E-BPA-28.

4.2.5.1 Description of Generation Supplied Reactive and Voltage Control

In addition to supplying real power, FCRPS generation facilities provide reactive power and voltage control to the transmission system. The NERC Interconnected Operations Services defines Generation Supplied Reactive and Voltage Control (GSR) as the provision of reactive capacity, energy, and maneuverability from a resource in order to control voltages to support transmission system reliability. Since Order 888, FERC issued Order 2003-A recognizing that non-affiliate generators are not entitled to compensation for GSR inside the band unless the transmission provider is compensating its own generators for GSR inside the band. In order to determine whether or not to continue compensating generators for inside the band GSR, BPA conducted a study of costs and benefits across ratepayers assuming continued and discontinued GSR inside the band compensation to all generators. Assuming continued compensation, the current trend of increasing and potentially uncertain GSR costs for inside the band shows COU customer benefits have begun to decrease while non-federal generator benefits have increased. This analysis also described the rate impacts of removing GSR inside the band compensation to generators that forecast a negative $6 million impact per year on COU customer's cost of delivered power, but would have $1 million benefit per year to regional ratepayers. It also projected that if the current non-affiliate generators with GSR rates file for adjustment in 2008, the net impact of the Supplemental Proposal to not pay Power Services for GSR inside the band would provide a $4.4 million benefit to regional rate payers. *See* WPRDS Documentation, WP-07-FS-BPA-13A. These additional tables provide explanation of the assumptions and inputs to the study of costs and benefits of current and proposed reactive power policy in this Supplemental Proposal. *See* Reactive Power Study, WP-07-E-BPA-29; and Reactive Power testimony, WP-07-E-BPA-28.

4.2.5.2 General Methodology for FY 2009

For FY 2009, BPA identified the FCRPS generation related components that are used in the production of both real and reactive power. These components, referred to collectively as "electrical plant," are the generator stator and rotor, exciters, voltage regulators, certain power plant equipment, step up transformers, and GI facilities. Also included is 50 percent of accessory electrical equipment. Electrical plant is used to supply both real and reactive power. Therefore, some fraction of the cost of electrical plant is allocated to the generation input for reactive power and voltage control. The remaining plant components are used only for real power production, so none of the costs of these components are allocated to the generation input for reactive power and voltage control. Plant components excluded from the allocation are dam structures, turbines, reactors, or any other items associated with water or nuclear fuel. BPA also allocated to the generation input for reactive power and voltage control the cost of real power losses associated with the flow of reactive power in the generation equipment, as well as the costs associated with synchronous condensing, both plant modifications and energy costs. BPA determined that the total annual cost to provide the generation input for Reactive Power and Voltage Control is $24.2 million for FY 2009. *See* WPRDS Documentation, WP-07-FS-BPA-13A.

4.2.5.3 Determining Costs of Electric Plant to Allocate to the Generation Input for Reactive Power and Voltage Control

Electrical plant is used to supply both real and reactive power. Therefore, some fraction of the cost of electric plant is allocated to the generation input for reactive power and voltage control. This section describes the methods for determining electrical plant costs.

4.2.5.3.1 Electrical Plant

The FCRPS generation-related components that are used in the production of both real and reactive power comprise the "electrical plant" and include the generator stators and rotors, exciters, voltage regulators, certain power plant equipment, step up transformers, and GI facilities. Also included is 50 percent of accessory electrical equipment. The costs of electrical plant (investment and O&M costs) are identified for the COE and Reclamation hydro projects. The cost of electrical plant for CGS is also identified.

The COE provided Plant in Service Unit Costs in which the COE assigns accounting codes to plant equipment with the associated investment as of September 2004. The turbine/generator costs are not separately identified, but are grouped together in the Electrical Plant costs. Based on interviews with the COE, it was determined that the generator/turbine allocation was approximately 50 percent. This provides a basis for assigning COE costs to electrical plant. The resulting investment for electrical plant is then used to prorate costs from the COE's Completed Plant Investment as reflected in the FCRPS financial statement dated September 30, 2004, for each hydro project. The resulting electrical plant investment does not include electrical replacements that are planned for the rate period. Planned electrical replacements are identified separately. *See* WPRDS Documentation, WP-07-FS-BPA-13A.

For Reclamation hydro projects, electrical plant investment costs (including interest) are determined from gross plant using the Reclamation's Gross Financial Statements dated September 30, 2004. The turbine/generator costs are not separately identified, but are grouped together in a Project Type Category 'Electric Plant in Service.' The generator portion of this category is estimated to be 50 percent using the same assumptions as applied to the COE projects. The resulting gross electrical plant investment is then depreciated to determine net electrical plant investment. The resulting electrical plant investment does not include electrical replacements that are planned for the rate period. Planned electrical replacements are identified separately. *See* WPRDS Documentation, WP-07-FS-BPA-13A.

4.2.5.3.2 COE/Reclamation Planned Electrical Replacements

Plant replacements that are planned to occur during the rate period were determined by using the capital plant program projections, FY 2005-2009. The projected activities include electrical plant, transmission modifications associated with generation integration and 50 percent accessory equipment on a plant-by-plant basis. The projected expenditures are used to determine the percentage applied to electrical plant versus non-electrical plant for each year.
These percentages are averaged over a five-year period to establish the percentage that is then applied to the budgeted capital replacement program for Corps and Reclamation hydro projects on a plant-by-plant basis to determine net electrical plant replacements. *See* WPRDS Documentation, WP-07-FS-BPA-13A.

4.2.5.3.3 CGS Electrical Plant

The Energy Northwest staff provided investment and depreciation data for items identified as electrical plant in the WP-02 Final Proposal. This data is valid for the Supplemental Proposal because there have been no significant modifications to the CGS. BPA retains the 0.0074 ratio of net electrical plant divided by net total plant as determined previously. The resulting ratio of 0.0074 is then used as an allocator in the Revenue Requirement Study, WP-07-FS-BPA-02, to determine annual costs of CGS electrical plant. *See* WPRDS Documentation, WP-07-FS-BPA-13A.

4.2.5.3.4 Operations and Maintenance (O&M) Costs for Electrical Plant

O&M costs associated with electrical plant are determined by using the percentages determined for Reclamation and the COE in the WP-02 Final Proposal. For the WP-02 Final Proposal, Reclamation staff determined the percentage of total O&M dedicated to electrical plant on a project-by-project basis. The percentages O&M dedicated to electrical plant are 42 percent for Corps and 45 percent for Reclamation. These percentages are applied to budgeted O&M for this Supplemental Proposal.

4.2.5.3.5 O&M for CGS

The Energy Northwest staff provided budgeted O&M expenses for CGS for the rate period. The ratio of 0.74 percent, which is the ratio of net electrical plant divided by net total plant, is used in the Revenue Requirement Study, WP-07-FS-BPA-02, to determine the portion of O&M to be allocated to electrical plant. *See* WPRDS Documentation, WP-07-FS-BPA-13A.

4.2.5.4 Factor to Allocate Electrical Plant Revenue Requirement for Reactive Power and Voltage Control

Electrical plant provides both real and reactive power. To allocate a portion of the cost of electrical plant to the provision of reactive power and voltage control, the electric plant is multiplied by a power factor of 0.95 (COE and Reclamation facilities). The use of 0.95 is established through NERC/WECC Standards and in Order 2003 FERC acknowledged that 0.95 was an industry standard. For the hydro projects, at a power factor of 0.95, allocates 10 percent of the total electrical plant revenue requirement to reactive power and voltage control. For CGS, the rated power factor of 0.975 is used, which allocates 5 percent of the total net electrical plant revenue requirement to reactive power and voltage control.

4.2.5.5 Synchronous Condenser Costs

Synchronous condensing involves the motoring of units to provide voltage and reactive control primarily to the transmission system, and in a limited quantity, to the generation facilities. This unique component is a necessary contributor to the reliability of the interconnected transmission system. These costs are allocated to Transmission Services as part of generation-supplied reactive. Two elements contribute to the plant's cost in the provision of synchronous condensing. These costs are investment in plant modifications necessary to provide synchronous condensing and the energy consumed by the plant while in the synchronous condensing mode. The investment in plant modifications allocated to Transmission Services is $365,000 per year. For energy consumption BPA forecasts 136,337 MWh of energy. Applying an estimated average PF rate of 27.33 mills/kWh to the energy consumed results in a total cost of $3,726,096. *See* WPRDS Documentation, WP-07-FS-BPA-13A. Synchronous condensing is not considered by BPA as either inside or outside the band operation nor is it part of the AEP methodology. This method excludes real power losses and inside the band costs associated with the AEP methodology that allocates a portion of the generation supplied plant to GSR service without regard to, or consideration of, inside or outside the band. Under the Supplemental Proposal, BPA will continue to receive compensation for synchronous condensing in FY 2008-2009.

4.2.5.6 Reactive Energy Losses

Real power (megawatts) must be produced to supply generator and exciter losses (generator stator and rotor (field) load and exciter losses). When reactive power is produced these losses increase. These losses were determined by using FCRPS generator data when the necessary data was available. Losses of 10 percent are allocated to the generation input for reactive power and voltage control. BPA forecasts 71,638 MWh of energy will be consumed to produce reactive power. An estimated average PF Preference rate of 27.33 mills/kWh is used to price the power, resulting in a total cost of $1,958,000. *See* WPRDS Documentation, WP-07-FS-BPA-13A.

4.2.5.7 Summary – Costs Assigned to Transmission Services for Generation Supplied Reactive Power and Voltage Control

Electrical Plant costs are determined through the Revenue Requirement Study using the percentages developed from Gross Plant Investments, Planned Replacements, and O&M. The Generation Integration cost basis was determined in the Transmission Services Settlement for FY 2007 and forecast for FY 2008-2009. To determine costs allocated to reactive, the Total Revenue Requirement for Electrical Equipment is multiplied by the appropriate power factor (0.95 for COE and Reclamation and 0.975 for CGS) that allocates $17,963,000 for COE and Reclamation and $170,000 for CGS. In addition to these, $365,000 costs for synchronous condenser modifications, $3.726 million costs for synchronous condenser power consumption, and $1.958 million costs for real energy losses are added to result in the total proposed annual cost allocation of $24,182,000 to Transmission Services for generation supplied reactive and voltage control for FY 2007 only. *See* WPRDS Documentation, WP-07-FS-BPA-13A. The forecast costs assigned to Transmission Services for GSR for FY 2008-2009 is $4 million each year for synchronous condensing costs associated with plant modification and energy consumed. An expected value of $12.5 million each year was used to set power rates. The forecast costs assigned to Transmission Services for GSR for FY 2008-2009 is approximately $4 million each year for synchronous condensing costs associated with plant modification and energy consumed.

Consistent with the Supplemental Proposal, an expected forecast value of $12.5 million each year was used to set power rates. This forecast amount reflects a range of $4 million to $20 million of revenue including the expected risk associated with GSR outside the band compensation and synchronous condensing. *See* WP-07-E-BPA-28 and pages 8-9.

4.3 Generation Inputs for Other Services

This section describes the method for allocating costs of Generation Dropping and Station Service. The following sections describe the methodology, identify the assumptions used in the methodology, and establish the generation input rate that is applied to determine the annual revenue forecast.

4.3.1 Generation Dropping

The BPA transmission system is interconnected with several other transmission systems. In order to maximize the transmission capacity of these interconnections while maintaining reliability standards, Remedial Action Schemes (RAS) are developed for the transmission grids. These schemes automatically make changes to the system when a contingency occurs to maintain loadings and voltages within acceptable levels. Under one of these schemes, Power Services is requested by Transmission Services to instantaneously drop large increments of generation (at least 600 MW). In order to satisfy this requirement the generation must be dropped (disconnected from the system) virtually instantaneously from a certain region of the transmission grid. Under the current configuration of the transmission grid, and the individual generating plant controls, Power Services can most expeditiously provide this service by dropping one of the Grand Coulee Third Powerhouse hydroelectric units (each of which exceeds 600 MW capacity).

Power Services previously contracted with an engineering company to work with the Reclamation and COE (owners of the Columbia River system plants) to evaluate the costs of providing this "generation drop" service. *See* WPRDS, WP-02-FS-BPA-05, at 85-86. BPA proposes to reuse the data and findings from the engineering company for this rate proceeding and apply an appropriate adjustment to hydro program data to reflect inflation.

4.3.1.1 General Methodology

The overall valuation approach considered two factors. First, the desired generation dropping service or "forced outage duty" causes additional wear and tear component on equipment that will incrementally decrease the life and increase the maintenance of the unit. The incremental replacement or overhaul cost is computed for each major component that is impacted by this service. Second, the incremental impact is evaluated by computing lost revenues during the outages required during replacement or overhaul of the equipment.

4.3.1.1.1 Determining Costs to Allocate to Generation Dropping

Historical data for the Grand Coulee Third Powerhouse generating units, as well as statistical data for other hydroelectric units, provided capital cost, O&M costs, and frequency of operation information for the generation dropping analysis. *See* WPRDS Documentation, WP-07-FS-BPA-13A. Stresses during "forced outage duty" on the equipment versus stresses during "normal operation" are compared. Through the application of this data, the incremental capital and/or O&M costs for the generation drop duty is developed. The analysis converts the incremental impacts of these factors that result from generation drop service into a percentage change in the life for each operation. The most likely type of overhaul or replacement that would need to be made and the estimated capital costs for that circumstance are evaluated in the analysis.

In addition to capital and O&M costs, the revenue lost during outages involving the overhaul or replacement of equipment is significant, especially when considering a generating unit with a capacity exceeding 600 MW. For purposes of this analysis, it is assumed that some outages could be scheduled to avoid most revenue losses required for routine maintenance. However, a cost is calculated for the outages that could not be scheduled to avoid lost revenues. It is assumed that these outages are longer than scheduled and/or unpredictable, and could not be scheduled to avoid a loss in total project generation. *See* WPRDS Documentation, WP-07-FS-BPA-13A.

4.3.1.1.2 Equipment Deterioration/Replacement or Overhaul

The effect of additional deterioration due to generation dropping is a reduced period of time between major maintenance activities, such as major overhauls or replacements. For purposes of this analysis a "major overhaul" is defined as maintenance activities where at least partial disassembly of the impacted equipment is required. The analysis focuses on evaluating the costs of additional, short-term deterioration of specific components or items for which statistical data were readily available. The costs of a major overhaul were derived from estimates or similar work performed in the past. The percentage life reductions were determined using industry standards or actual project records. For example, turbine overhaul is a major maintenance effort that will be increased in frequency as a result of more frequent severe duty cycles. *See* WPRDS Documentation, WP-07-FS-BPA-139A.

4.3.1.2 Summary

The factors described above were analyzed for their application on a single generating unit at the Grand Coulee Third Powerhouse and their effects combined to produce a single, overall cost associated with each generation drop.

This analysis includes the time between major overhauls or replacement, and increased routine maintenance the major cost components that would be affected by a generation dropping. From the analyses, the total cost associated with a single generator drop of one of the Grand Coulee Third Powerhouse Units was calculated to be $264,047. *See* WPRDS Documentation, WP-07-FS-BPA-13A.

This is comprised of $3,198 in additional maintenance costs, $52,051 in deterioration and risk costs to replace damaged or failed equipment, and $208,798 in lost revenues. The sum of $264,047 is multiplied by the average of 1.5 generation drops required per year for a total annual cost of $396,071 per year.

4.3.2 Station Service

Station Service refers to real power taken directly off the BPA power system for use by Transmission Services at substations and other facilities. Transmission Services obtains Station Service for many of its facilities directly from the BPA transmission system. The purpose of this analysis is to identify the amount of Station Service being directly supplied by Power Services for use at BPA substations. This does not include Station Service that is being purchased by Transmission Services from another utility or supplied by another utility through contractual arrangements.

4.3.2.1 General Methodology

BPA will allocate costs to Station Service by estimating the amount of kilowatt-hour usage for each substation. This approach is necessary because there are few locations on the BPA system where station service use is metered. This methodology is based on the amount of primary Station Service transformation installed at each substation location multiplied by a load factor associated with average substation service usage. The installed station service capacity at each BPA substation was identified and classified into either small, medium, or large substations based on the amount of installed primary station service capacity. Historic data on usage, where meter data are available, was gathered for a number of substations in each category to calculate an average load factor. The results of this portion of the study showed that the load factor is similar for each category of substation range from 6.7 percent to 10.6 percent. An overall average (weighted by transformer capacity) load factor of 9.4 percent is proposed for calculating the station service usage. *See* WPRDS Documentation, WP-07-FS-BPA-13A.

4.3.2.2 Determining Costs to Allocate to Station Service

BPA determines the estimated Station Service kilowatt-hour usage for each substation by multiplying the average load factor of 9.4 percent by the installed primary Station Service capacity and then multiplying this by the number of hours in the month. The historic average Station Service kilowatt-hour use for the Ross Complex and the Big Eddy/Celilo Complex has been added to the calculated numbers for the other substations to develop the station usage for the system. The Ross Complex and Big Eddy/Celilo Complex are not normal substation facilities and do not follow the developed methodology. The system station service use is estimated to be 6,368,389 kWh per month, or an average of 8.8 MW. The estimated average PF Preference rate of 27.33 mills/kWh is used to price the power resulting in a total cost of $2.1 million per year. *See* WPRDS Documentation, WP-07-FS-BPA-13A.

4.4 Segmentation of COE and Reclamation Transmission Facilities

This section covers segmentation of COE and Reclamation Transmission Facilities. The analysis covers transmission facilities owned by the COE and Reclamation. The COE and Reclamation own transmission facilities associated with their respective generating projects. BPA is proposing to include all COE and Reclamation costs in the generation revenue requirement, including the costs functionalized to transmission. Therefore, the COE and Reclamation transmission investment is identified and segmented so that the annual cost of these facilities may be developed and a portion assigned to Transmission Services.

BPA will assign the COE and Reclamation transmission related investment to three segments: Generation Integration (GI), Network, and Utility Delivery. The GI costs would be assigned to generation. As noted above, a share of the GI cost is used in the calculation of generation input costs for ancillary services. The remaining COE and Reclamation transmission investment would be segmented to Network and Utility Delivery. The annual cost of these Network/Utility Delivery investments is credited to the generation revenue requirement, and may be included in BPA transmission revenue requirement and assigned as an expense to the appropriate segment. The relevant segment definitions and proposed treatment are described below.

4.4.1 Generation Integration (GI)

GI facilities are those facilities that connect the Federal generators to the BPA network. This segment includes generator step-up (GSU) transformers. BPA will continue to assign GI costs to generation.

4.4.2 Integrated Network

Integrated network facilities are those facilities that supply bulk power to the other transmission segments and operate at voltages of 34.5 kV and above. BPA will continue to assign these costs to transmission.

4.4.3 Utility Delivery

Utility delivery facilities are those facilities that deliver power to BPA public utility customers at voltages less than 34.5 kV. BPA will continue to assign these costs to transmission. The segmentation of these facilities is consistent with the segment definitions used in Transmission Services' most recent segmentation study. *See* Segmentation Study, TR-02-FS-BPA-02. To the extent that the segment definitions change based on the outcome of a succeeding transmission rate case, the cost of these COE and Reclamation transmission facilities may be placed in the appropriate transmission segment in the future Power rates cases.

4.4.4 COE Facilities

The transmission facilities owned by the COE are primarily GSU and associated equipment at the plants. These costs are all GI, which is assigned to power. The only exception is at the Bonneville Project. At Bonneville Powerhouse No. 1, the COE owns the switching equipment located on the dam that is used for both Network and GI. *See* WPRDS Documentation, WP-07-FS-BPA-13A.

4.4.5 Reclamation Facilities

Reclamation usually owns the lines and substations at its plants. The primary function of these facilities is to connect the generators to the network, but at some plant substations there are facilities that perform either a network or delivery function. Information used in this Study shows the allocation of the line and substation investment at each Reclamation project into the appropriate segment. *See* WPRDS Documentation, WP-07-FS-BPA-13A, for the Columbia Basin project (Grand Coulee). *See* WPRDS Documentation, WP-07-FS-BPA-13A for the other Reclamation projects. The available Reclamation investment data did not disaggregate costs to the equipment level. To develop investment by segment, typical costs were used as a proxy for major pieces of equipment. The proxy investment by segment was divided by the total proxy investment for each station total to develop a percentage for each segment as a percentage of the total transmission investment. The segment percentage was multiplied times the total transmission investment for each station to determine the segment investment. *See* WPRDS Documentation WP-07-FS-BPA-13A.

5. REVENUE FORECAST

This section describes the revenue forecast prepared for the 2007 Supplemental Final Proposal and presents the results of that forecast. This forecast differs from the forecast presented in the WP-07 Final Proposal. First, this forecast now includes IOU REP load sales because BPA will be operating an REP in FY 2009. Second, this forecast includes updates to some long-term contract rates that have changed since the last rate filing. Third, this forecast includes a forecast of wind integration within-hour balancing service revenues from wind resources that was not included in the WP-07 Final Proposal. This forecast includes revenues for FY 2008 and FY 2009.

5.1 Overview

The revenue forecast presents BPA's expected level of sales and revenue for the period, FY 2008-2009. BPA prepares two revenue forecasts. One uses current rates, and the other uses proposed rates. These forecasts are used to demonstrate that proposed rates cover BPA's revenue requirement. The revenue test is described in the FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10, Section 5.1.1. The base rates placed in effect October 1, 2006, are used in the calculation of revenue at current rates for FY 2008-2009. The proposed rates are developed in the FY 2009 WPRDS based on the load forecast in the FY 2009 Load Resource Study, WP-07-FS-BPA-09.

The proposed rates are then applied to those loads to create a proposed revenue forecast for FY 2009. The revenue from this forecast is shown in FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 3.6.2.

5.2 Sources of BPA Revenue

Power Services' revenue is divided into five sources. The first (and largest) source of revenue is the sale of firm power under Subscription (including Slice) contracts to regional public agencies and Federal agencies. In FY 2007 this revenue totaled $1,748 million. In FY 2008, this revenue is projected to total $1,775 million.

The second revenue source is long-term contractual obligations where the prices are already determined by contract or by contract formula. This source includes contracts with several IOUs, municipalities, Federal agencies, public agencies, and power marketers. BPA also receives credit for COE and Reclamation payments to the U.S. Treasury of revenues they collect from owners of downstream projects for benefits provided by upstream projects. In FY 2007 the sum of these revenues totaled $171 million. In FY 2008, the sum of these revenues is expected to total $169 million.

The third source of revenue is from short-term energy sales, where prices are determined by the market. This source includes power sold on a monthly, weekly, daily, or hourly basis, as well as some revenues earned from the sale of options to purchase or sell power. In FY 2007, short-term power sales generated gross revenue of $670 million, excluding bookouts. Bookouts are a common practice in the utility industry to minimize transmission expenses when deliveries of two transactions of equal size moving in opposite directions are cancelled out by the transacting parties. Bookouts have been required to be subtracted from both revenue and expenses according to GAAP since FY 2004, but the dollars still change hands as if the transaction occurred. Bookouts in FY 2007 totaled $95 million. In FY 2008, revenue from short-term energy sales is expected to total $704 million, and bookouts are currently $103 million.

The fourth source of revenue is from the sale of generation inputs for ancillary and reserve services. This revenue is generation inputs sold to Transmission Services. In FY 2007, revenue from generation inputs and reserve product sales was $82 million. In FY 2008, revenue from ancillary and reserve product sales is expected to be $68 million.

The last revenue source is revenue credits from the U.S. Treasury and revenues from miscellaneous sources, such as payment for energy efficiency services, storage fees, contract administration, contract termination and settlement fees, low-voltage delivery charges, reimbursement of transfer fees, and interest on late payments. The credits include Section 4(h)(10)(C) and those associated with the Colville Settlement. The credit associated with BPA payments to the Colville Tribe for the use of reservation land for power production is fixed by statute. In FY 2007, these credits and revenue from other miscellaneous sources totaled $92 million. In FY 2008, these credits and other revenue are expected to total $123 million.

5.2.1 Subscription Sales for FY 2009

Sales of firm power under Subscription contracts are the basic products for which the proposed rates are designed. Most of BPA firm power will be sold under these contracts. The revenue from these contracts is estimated by applying the PF-07 rates (or the proposed PF-07R rates) to the projected billing determinants. The LDD is also taken into consideration. The Conservation Rate Credit (CRC) is reflected in BPA expenses rather than in the revenues, even though it is included with the rate schedules. When applying WP-07 rates to these sales, the revenue averages $1,802 million. When applying proposed rates to these sales, the revenue totals $1,778 million for the rate period (including the estimated Slice true-up).

5.2.2 Contractual Formula Rates

Some of BPA's contracts include specified formulas for calculating rates. These rates are based on a variety of factors, including changes in the PF rate, changes in the BPA Average System Cost (BASC), and the price of oil and gas. Contracts that could be in either the sale or exchange mode are assumed to be in the exchange mode for FY 2009, or until the contracts expire.

Revenue from Power Services' in-region and out-of-region long-term contract sales is forecast to total $154 million for FY 2009. (*See* FY 2009 WPRDS Documentation, Table 3.6.2, WP-07-FS-BPA-13A, lines 11, 12, 22, 23, 28, and 44.)

5.2.3 Short-Term Market Sales and Power Purchase Expense—Forecast

For rate development purposes, BPA projects firm resources based upon critical (*i.e.,* 1937) water conditions. The revenue forecast includes BPA's sales of energy created by streamflow in excess of critical water. This power is sold under the FPS rate schedule for periods as short as one hour or as long as an entire year.

5.2.3.1 Short-Term Market Sales and Power Purchase Expense—Calculation

The calculation of short-term market sales begins by calculating monthly HLH and LLH energy surpluses and deficits in RiskMod. This analysis, referred to as the 50-water-year run of RiskMod, involves estimating energy surpluses and deficits using forecasted loads, non-hydro resources, and varying hydro generation. RiskMod uses results from two hydroregulation models, Hydro Simulation (HydroSim) and the Hourly Operating and Scheduling Simulator (HOSS), plus load forecasts, to compute the available HLH and LLH surplus energy, as well as HLH and LLH energy deficits, in the Federal hydro system under varying streamflow conditions. (*See* FY 2009 Risk Analysis Study, WP-07-FS-BPA-12, section 2.1.)

The 50-water-year run of RiskMod is used to forecast the amount of surplus energy available for sale as well as the amount of power purchases needed to meet BPA loads under different water conditions. The available energy surplus or deficit is determined by subtracting total firm loads from total Federal generation using forecast Federal hydro generation for 50 historical water years under current hydro operating constraints. The 50 historical water years cover a broad spectrum of streamflow conditions from very dry to very wet. The results of the 50-water-year run of RiskMod and the resulting balancing sales and purchases are shown in Tables 3.8.1 and 3.8.2 of the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A.

5.2.3.2 Short-Term Market Sales and Power Purchase Expense – Risk Sensitivity

Surplus energy revenues and purchased power expenses are analyzed using RiskMod. RiskMod estimates HLH and LLH surplus energy revenues and purchased power expenses for the 50 water years based on results from the 50-water-year run of RiskMod. HLH and LLH prices used in the analysis are from AURORA. (*See* FY 2009 Market Price Forecast Study Documentation, WP-07-E-BPA-47A.) BPA forecasts revenue from short-term sales will total $599 million in FY 2009. (*See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 3.8.1.)

BPA projects that expenses associated with short-term purchases will total $75 million during FY 2009. Table 3.6.1, lines 59 and 62. The forecast revenues from RiskMod for short-term market sales and purchased power expenses are noted in Tables 3.8.1 and 3.8.2, respectively, of the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A.

5.2.3.3 Augmentation Purchase Expense

BPA projects the need to acquire 313 aMW at a cost of $161 million in FY 2009 in order to meet firm loads. This includes both executed and forecasted augmentation purchase estimates. For FY 2009, BPA assumed its executed Slice Excess Requirements Energy (ERE) contract with certain Slice customers to be an augmentation purchase of approximately 13 aMW. BPA's Slice ERE purchase of approximately 13 aMW is included in BPA's estimated 313 aMW. The cost of the remaining 300 aMW is based on projected prices using the AURORA model assuming critical water conditions. These prices and the corresponding cost of these augmentation purchases are documented in the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 3.8.3, and can also be found in Table 3.6.2, Summary Table, line 56.

5.2.3.4 Section (4)(h)(10)(C) Credits and Colville Settlement

The average annual Section 4(h)(10)(C) operational credits that BPA can claim when making its annual U.S. Treasury payments were obtained from RiskMod. These average annual values were derived by estimating the amount of Section 4(h)(10)(C) operational credits that BPA could claim under each of the 50 historical streamflow conditions and then adding them to the other 4(h)(10)(C) credits BPA will receive. BPA determined the additional purchased power costs of the fish and wildlife recovery programs by comparing purchased power expenses associated with FCRPS operations before any restrictions were placed on river operations with FCRPS operations for fish mitigation. BPA uses the generation that could have been achieved without the current restrictions as a baseline. The critical period Firm Energy Load Carrying Capability (FELCC), before changes for fish and wildlife operations, became the base firm energy load for this forecast. The cost of the increased purchases was estimated using RiskMod and the market price forecast. A portion of the increased purchased power expenses (22.3 percent) is included in the Section 4(h)(10)(C) credit. The total Section 4(h)(10)(C) credit is forecast to be $88 million for FY 2009. The Section 4(h)(10)(C) credit calculations are shown in Table 3.5 of the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A. The Treasury credit for the Colville Settlement is set by legislation at $4.6 million per year.

5.2.4 Generation Inputs to Ancillary and Reserve Products

Revenue from generation inputs for ancillary services and other services sold by Transmission Services that contain a generation component includes: Load Regulation, Control Area Reserves, Transmission Losses, Remedial Action, Energy Imbalance and Wind Integration – Within-Hour Balancing Service. Also, the revenue Power Services receives from Reserve Services it provides to others is included.

In FY 2008, revenue from ancillary products is expected to total $63 million, and revenue received from the sale of reserve services is expected to total $5 million. During FY 2009, these revenues are expected to be $79 million and $4 million, respectively. The revenue forecast in FY 2009 includes $19.0 million from the sale of generation inputs for wind integration – within-hour balancing service. (*See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 3.7.)

5.2.5 Energy Efficiency

BPA projects revenues of about $22 million per year from the sale of energy efficiency products and services. Energy efficiency revenues are documented in BPA budget estimates prepared in 2007. (*See* WPRDS Documentation, WP-07-FS-BPA-05A, Table 3.9.)

5.2.6 Low Density Discount

The calculation of the LDD for a representative but unidentified customer is shown in Table 3.10 of FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A. The calculation is compared to the output from the RFA database to demonstrate how the LDD calculations are done.

5.3 Sales Forecasts

The proposed sales forecasts used in the revenue forecast are the source of energy and demand billing determinants used to calculate rates and revenues. The energy load forecasts include forecast energy loads of PF, and FPS sales. The energy load forecasts used in this rate proposal are documented in the FY 2009 Load Resource Study*,* WP-07-FS-BPA-09, and FY 2009 Load Resource Study Documentation, WP-07-FS-BPA-09A.

The firm loads under Subscription contracts expected using current rates are the same as the firm loads expected using proposed rates. Because the forecast of Subscription power sales is the same, the forecast of surplus market sales and purchased power expenses is also the same. The only thing that differs in these forecasts is the rate at which Priority Firm requirements power is sold and the revenue from those sales.

5.4 Revenue Forecast Methodology

The first step in developing the revenue forecast is to apply rates to the forecast of firm sales. For long-term contracts, because they contain confidential information, that calculation is made by individual contracts separately, and then those revenues are summed and added to the forecast. The sales made under regional Pre-Subscription FPS contracts are multiplied by the specific contract rates. Because these contracts contain confidential information, the billing determinants and revenues are totaled. The revenues are reported for HLH Energy, LLH Energy, Demand, and Load Variance. Some of these contracts have only HLH and LLH energy billing determinants.

Subscription power sales billing determinants from the sales forecasts are applied to the appropriate set of PF or IP rates to calculate BPA's expected revenue from these contracts. Revenues from long-term contract sales are calculated by applying the contract rates to these contracts in the same manner as the revenues are calculated from pre-Subscription contracts. These contracts also contain confidential information; therefore, the contract revenues are summed and displayed together. Revenues from miscellaneous products and services and ancillary and reserve power products are added to the power revenues. Documentation for Generation Inputs for Ancillary and Reserve Services is contained in FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, section 4.

5.4.1 Other Factors Affecting Forecasted Revenues

Other factors affecting forecasted revenues include the LDD and Irrigation Rate Mitigation sales, which are described below.

5.4.1.1 Low Density Discount (LDD)

Rate discounts due to the LDD are projected to be about $24.9 million per year during the proposed rate period. An example of how the LDD is calculated for a particular customer is shown in the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Table 3.10.

5.4.1.2 Irrigation Rate Mitigation Sales

Sales to irrigation loads total 197 aMW, and the revenue from these Irrigation Rate Mitigation sales is based on contractually specified FPS rates that are lower than the PF rate, but change by the amount of the base PF rate change.

5.5 FY 2008 Revenue

Forecast revenue using current rates for FY 2008 is shown in Table 3.6.1 of the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A. Revenue in FY 2008, excluding bookouts, is projected to total $2,840 million. Revenue from firm power sales to public utilities and Federal customers at the PF-07 and FPS-07 rates is projected to total $1,845 million in FY 2008. This amount excludes the return of overcharges for REP settlements.

Long-term surplus contract revenues, including sales at PPL-90, WNP-3 Exchange rate, COE and Reclamation reserve energy and irrigation pumping rates, and other contracts that are determined by prior contractual arrangements, are projected to be $99 million in FY 2008. *See* Table 3.6.1, line 28 plus 44, of the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A.

Revenue from the sale of generation inputs for ancillary and reserve services is projected to be $63 million in FY 2008.

Revenues from Section 4(h)(10)(C) credits are projected to be $96 million in FY 2008. In future years, projected Section 4(h)(10)(C) credits are estimated using the average of 50 water conditions. Revenue credited to BPA associated with the Colville Settlement is $4.6 million in FY 2004 and beyond, as defined in legislation.

Miscellaneous revenues from the Energy Service activities, Green Tags, Green Premiums, and other sources are projected to total $21 million in FY 2008. *See* Table 3.6.1, line 46 and 47, of the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A.

5.6 Revenue for FY 2009

Forecast revenue under current rates for FY 2009 is found in Section 3.6.1 of the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, and revenues forecasted under proposed rates for the FY 2009 rate period are found in Table 3.6.2. Pre-Subscription contract sales to preference customers are made at the FPS rate. Long-term contract sales to IOUs and marketers (contract terms longer than 12 months) are included with other long-term contracts.

5.6.1 Revenues for FY 2009 at Current Rates

Revenue estimated under current 2007 rates is shown in Table 3.6.1 of the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A. Total revenue from all sources, except residential exchange sales, is projected to be $2,759 million in FY 2009.

5.6.2 Revenues for FY 2009 at Proposed Rates

Revenue estimated under proposed rates is shown in Table 3.6.2, line 51, of the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A. Revenue at proposed rates, excluding the revenue from REP sales, is projected to be $2,737 million in FY 2009. This does not include returns of overcharges for past settlements.

6. RATE SCHEDULE DESCRIPTIONS

The wholesale power rates developed in the FY 2009 WPRDS are presented in two sections and one appendix in the Wholesale Power Rate Schedule and GRSPs. *See* 2007 Supplemental Wholesale Power Rate Schedules (FY 2009) and General Rate Schedule Provisions (FY 2009), WP-07-A-05A. The first section contains the proposed rate schedules. Each rate schedule states the customers for whom the rate schedule is available, proposed rates for the products offered under the schedule, billing factors, and references to sections of the GRSPs that apply to that rate schedule. The rate schedules also state appropriate transmission purchasing policies for power customers. The GTA Delivery Charge is also included. The second section contains the proposed GRSPs for power rates. The GRSPs include adjustments, charges, special rate provisions, and two lists of definitions, one of products and services, and one of rate schedule terms. Appendix A contains the final update of the FY 2002-2011 Slice Rate Methodology. Appendix B contains the Customer Lookback Credit for the REP for FY 2002-2006 which applies to customers that purchased power at the PF-02 Priority Firm rates under their Subscription contracts.

Purchases under the PF-07R (including the PF Exchange rate), NR-07R, and IP-07R rates are subject to the CRAC (including the NFB Adjustment), the DDC, and the Emergency NFB Surcharge. The CRC and the GEP are not available under the PF Exchange rate, but are available under most of the other PF, NR, and IP products. The Slice Product will be subject to the CRC; however, it will not be subject to the CRAC, DDC, the Emergency NFB Surcharge, or the GEP. *See* Partial Resolution of Issues, Attachment 1, Administrator's Final Record of Decision, WP-07-A-02, July 2006, for additional information on Demand, Load Variance and other issues for each rate schedule.

6.1 Priority Firm Power Rate, PF-07R

The proposed PF-07R rate schedule replaces the PF-07 rate schedule for FY 2009. The PF-07R rate schedule is available for the purchase of power by eligible COUs, Federal agencies, and utilities participating in the REP under section 5(c) of the Northwest Power Act. PF power must be used to meet the purchasers' firm loads within the PNW.

The PF-07R rate schedule includes sections applicable to different types of purchasers under the 2002 Subscription contracts or the Residential Purchase and Sale Agreements (RPSA). The PF Preference rate is available to meet the general requirements of COUs and Federal agencies. The PF Exchange rate is available to utilities participating in the REP. Utilities must have RPSAs to be eligible to purchase under the REP. PF Preference rates for Demand and Energy, Load Variance, and Slice have been proposed. At its discretion, and subject to specified limitations, BPA also may make available the Flexible PF Rate Option, which includes rates and billing factors as mutually agreed upon by BPA and the Purchaser. *See* Section 2.6.

The PF-07R Demand rate is monthly differentiated. The PF-07R Energy rates are monthly and diurnally differentiated, except for the PF Exchange rate, which is proposed to be a single annual Energy rate subject to a Supplemental 7(b)(3) Rate Charge established specifically for each respective utility. This Supplemental 7(b)(3) Rate Charge is subject to adjustment during FY 2009 if any utility participating in the REP has its ASC modified during the year. *See* Sections 2.1 and 2.2 of this Study for a description of these rates.

Most purchases under the PF-07R rate schedule are subject to certain provisions of the GRSPs, including, among others, the CRAC (including the NFB Adjustment), the DDC, the Emergency NFB Surcharge, the TAC, LDD, and the Unauthorized Increase Charge (UAI Charge). If some customers choose to purchase the PF Partial Service Complex Product, they can be subject to the

Excess Factoring Charge. These are discussed in Section 2 of this Study. Purchases under the PF-07R rate schedule are subject to the BPA billing provisions.

6.1.1 Conservation Rate Credit (CRC)

The proposed CRC is available to those purchasing under the PF-07R (except for PF Exchange rate) and NR-07R rate schedules. BPA has included the CRC to encourage the regional development of incremental energy efficiency and renewable resources by BPA customers. *See* Section 2.10 of this Study for further information.

6.2 New Resource Firm Power Rate (NR-07R)

The proposed NR-07R rate schedule replaces the NR-07 rate schedule for FY 2009. The NR-07R rate schedule is available for purchase of power by IOUs under net requirements contracts for resale to consumers and to COUs for NLSLs. The structure of the NR-07R rate schedule is parallel to the PF-07R rate schedule to the extent appropriate.

Rates are proposed for NR Demand, Energy, and Load Variance. At its discretion, and subject to specified limitations, BPA also may make available the Flexible NR Rate Option, which includes rates and billing factors as mutually agreed to by BPA and the purchaser, as limited by the GRSPs. The NR rate schedule specifies which transmission rate schedule(s) may apply to purchasers under the NR rate schedule. The NR-07R rate includes a monthly differentiated Demand rate and monthly and diurnally differentiated Energy rates. The energy rate is subject to a Supplemental 7(b)(3) Rate Charge. Purchases under the NR-07R rate schedule are subject to certain provisions of the GRSPs, including, among others, the CRAC (including the NFB Adjustment), the DDC, the CRC, the LDD, the TAC, the UAI Charge, and for some products, the Excess Factoring Charge. These are discussed in Section 2 of this Study. Purchases under the NR-07R rate schedule are subject to the BPA billing process.

6.3 Industrial Firm Power Rate (IP-07R)

The proposed IP-07R rate schedule replaces the IP-07 rate schedule for FY 2009. The IP-07R rate schedule is available to DSI customers for firm take-or-pay block power to be used in their PNW industrial operations.

The IP-07R rate schedule includes a monthly differentiated Demand rate and Energy rates that continue to be monthly and diurnally differentiated and subject to a Supplemental 7(b)(3) Rate Charge. Purchases under the IP-07R rate schedule may be for one year and are subject to provisions of the GRSPs, as listed in the rate schedule, including the Supplemental Contingency Reserves Adjustment (SCRA), the CRAC (including the NFB Adjustment), the DDC, and UAI charges. The Load Variance Rate may be applicable if other products are purchased. Purchases under the IP-07R rate schedule are subject to the BPA billing process.

6.4 Firm Power Products and Services Rate (FPS-07R)

The FPS-07R rate schedule is available for purchase of Firm Power, Capacity, and Capacity Without Energy, Supplemental Control Area Services, Shaping Services, Reservation and Rights to Change Services and Reassignment or Remarketing of Surplus Transmission Capacity inside and outside the Pacific Northwest for the period ending September 30, 2009. The proposed FPS-07R rate schedule supersedes the FPS-07 rate schedule for FY 2009. Similar to the FPS-07 rate, the FPS-07R contains a Flexible rate. *See* Section 2.5 and 2.6 of this Study. The Flexible rate is a market-based rate that is negotiable. The Flexible rate may have a demand component, an energy component, or both, and is subject to a Supplemental 7(b)(3) Rate Charge. Unbundled products also are available under the FPS-07R rate schedule at Flexible rates as mutually agreed by the contracting parties. Applicable transmission rates will apply to the extent required to purchases of firm power under the FPS-07R rate. Purchases under the FPS-07R rate schedule also are subject to BPA billing process.

7. COST RECOVERY ADJUSTMENT CLAUSE

7.1 Cost Recovery Adjustment Clause (CRAC)

The proposed CRAC is an upward adjustment to the FY 2009 posted wholesale power rates. It recovers additional revenues to increase the probability that BPA will be able to meet its obligations to the U.S. Treasury. The amount of incremental net revenue to be collected is calculated by a subtracting Power Services' Accumulated Modified Net Revenues (AMNR) (as defined by the CRAC GRSP) from the annual Threshold. If this amount is negative, there is no CRAC; if this amount is positive, a CRAC will be implemented to collect the lesser of this amount and the CRAC cap.

The CRAC applies to Light Load Hours (LLH) and Heavy Load Hours (HLH) energy rates and Load Variance sales under these firm power rate schedules:

- PF-07R [Preference (excluding the PF Slice Product) and PF Exchange];
- Industrial Firm Power (IP-07R);
- New Resource Firm Power (NR-07R);
- BPA's contractual obligations for Irrigation Rate Mitigation Product sales.

The CRAC does not apply to:

- sales under the PF Slice Product; or
- power sales under Pre-Subscription contracts to the extent prohibited by such contracts;
- Demand Sales (however, if a trigger event under the NFB Adjustment increases the CRAC cap, and the CRAC triggers for an amount greater than the original cap, the amount of CRAC revenue in excess of the original cap will be collected through an increase to all demand, energy, and Load Variance Rates proportionately); or
- DSI financial benefits.

The CRAC would be applied to power deliveries beginning in October of FY 2009 if Power Services' AMNR is below the threshold in calculations performed in September 2008. Any such increase would remain in effect through September of FY 2009. The level of planned revenues to be collected through the CRAC is limited to the lower of the annual Maximum CRAC Recovery Amount in Table 7.1, or the amount by which the AMNR is below the threshold.

Table 7.1
CRAC Trigger Thresholds and Annual Caps
(dollars in millions)

AMNR Calculated at end of Fiscal Year	CRAC applied to Fiscal Year	CRAC Threshold in AMNR	Approx. Threshold as Measured in PS Reserves	Maximum CRAC Recovery Amount (CRAC Cap)*
2008	2009	($29.3)	$750	$36

* The Maximum CRAC Recovery Amount (Cap) may be modified by the NFB Adjustment (if triggered) calculated at the end of FY 2008.

7.1.1 National Marine Fisheries Service Federal Columbia River Power System Biological Opinion Adjustment (NFB Adjustment)

The NFB Adjustment results in an upward adjustment to the cap on the CRAC applicable to FY 2009, defined in Table 7.1, if additional fish and wildlife costs, or decreased revenues, arise from specific changes in the anadromous fish portion of Fish and Wildlife cost categories, and only when those financial impacts result from changes in FCRPS Endangered Species Act (ESA) compliance actions as required by a court order (including court-approved agreements), an agreement related to litigation, a new National Marine Fisheries Service/Federal Columbia River Power System Biological Opinion (NMFS FCRPS BiOp), or Recovery Plans under the ESA. Such triggering events are termed NFB Trigger Events, and they are defined below. Financial impacts include forgone revenue, power purchases, direct program expense, fish credits, COE and Reclamation operations and maintenance, and capital repayment. The NFB Adjustment will apply to HLH Energy, LLH Energy, Demand, and Load Variance rates. Financial impacts will be calculated net of estimated section 4(h)(10)(C) credits. *See* Supplemental Risk Analysis Study, WP-07-FS-BPA-12, for additional information on the NFB Adjustment Calculation.

7.2 Emergency NFB Surcharge

The Emergency NFB Surcharge (NFB Surcharge) is a charge applicable to certain BPA customers and is intended to recover certain costs. This Emergency NFB Surcharge is separate from the NFB Adjustment. If an NFB Trigger Event (defined below) implements both an NFB Surcharge and an NFB Adjustment, the NFB Adjustment amount will be reduced by the amount of such NFB Surcharge.

The NFB Surcharge addresses the fact that the CRAC does not produce revenues in the same fiscal year in which the financial effects that cause the CRAC to trigger occur, and this delay of the revenue would be problematic if BPA were in a cash crunch at the time of the NFB Trigger Event. The Surcharge is a within-year increase and may be implemented for FY 2009 for NFB events that occur in FY 2009.

The Surcharge applies to Heavy Load Hour, Light Load Hour, Demand, and Load Variance sales for power customers under the following firm power rate schedules:

- PF-07R [Preference Rate (excluding the PF Slice Product) and PF Exchange Power];
- Industrial Firm Power (IP-07R);
- New Resource Firm Power (NR-07R); and
- BPA's contractual obligations for Irrigation Rate Mitigation Product sales.

The Surcharge does not apply to sales under the following:

- the PF Slice Product
- Pre-Subscription contracts to the extent prohibited by such contracts;
- DSI financial benefits.

An NFB Trigger Event is an event of one of the following four kinds that results in changes to BPA's FCRPS ESA obligations compared to those in the WP-07S Final Proposal, as modified prior to this Trigger Event:

- A court order in *National Wildlife Federation vs. National Marine Fisheries Service*, CV 01-640-RE, or any other case filed regarding a NMFS-issued FCRPS BiOp, or any appeal thereof ("Litigation");
- An agreement (whether or not approved by the court) that results in the resolution of issues in, or the withdrawal of parties from, the Litigation;
- A new NMFS FCRPS BiOp; or
- A new BPA obligation to implement Recovery Plans under the ESA that results in the resolution of issues in, or the withdrawal of parties from, the Litigation.

Financial Effects of a Trigger Event are the net reductions (if any) in net revenue within the fiscal year due to the Trigger Event that affect power sales revenue, fish and wildlife credits, power purchases, direct program expenses of the anadromous fish component of BPA's fish and wildlife program, Corps of Engineers and Bureau of Reclamation Operations and Maintenance expenses, and amortization of capital costs when compared with the estimate of the foregoing revenues, costs, and obligations in the WP-07S Final Proposal as modified prior to this Trigger Event. These effects are the total effects on the Federal system, including the effects borne directly by Slice Customers.

7.3 Dividend Distribution Clause (DDC)

The proposed DDC is a rate adjustment establishing criteria for the distribution of funds to customers. The DDC enables BPA to distribute funds to eligible firm power customers and establishes the mechanism to be used to make a distribution. The amount of the distribution is calculated by subtracting the DDC Threshold in Table 7.2 from Power Services' AMNR. If the resulting amount is negative, there is no DDC; if it is positive, a DDC in that amount will be implemented.

The DDC applies to LLH and HLH energy and Load Variance sales subject to these firm power rate schedules:

- PF-07P [Preference Rate (excluding the PF Slice Product) and PF Exchange Power];
- Industrial Firm Power (IP-07R);
- New Resource Firm Power (NR-07R);
- BPA's contractual obligations for Irrigation Rate Mitigation Product sales.

The DDC does not apply to:

- sales under the PF Slice Product
- power sales under Pre-Subscription contract to the extent prohibited by such contracts
- Demand Sales; and
- DSI financial benefits.

The adjustment would be applied to power deliveries beginning in October of FY 2009 if the threshold is exceeded in calculations in September 2008. Any such decrease would remain in effect through September of FY 2009. The level of planned rate decrease through the DDC is limited to the amount that would decrease the LLH energy rate to 1 mill/kWh.

Table 7.2
DDC Thresholds
(dollars in millions)

AMNR Calculated at end of Fiscal Year	DDC applied to Fiscal Year	DDC Threshold in AMNR	Approx. Threshold as Measured in PS Reserves
2008	2009	$270.7	$1,050

8. AVERAGE SYSTEM COST FORECAST

8.1 FY 2009-2013 Average System Cost Forecast – Proposed 2008 ASCM

This section presents the forecasts of FY 2009-2013 ASCs and REP loads for six investor-owned utilities (IOUs) and three consumer-owned utilities (COUs) that may participate in the REP pursuant to section 5(c) of the Northwest Power Act, 16 U.S.C. § 839c(c). The forecasts of ASCs and exchange loads are based on BPA's 2008 Average System Cost Methodology (ASCM) Record of Decision, published on June 30, 2008. The 2008 ASCM is currently pending before the Commission in a separate proceeding. For specific definitions and details on the 2008 ASCM, *see* www.bpa.gov/corporate/ASCM.

8.2 Expedited Review Process

The February 7, 2008, Federal Register (73 Fed. Reg. 7270) announced the commencement of an ASC expedited review process (Expedited Process). The Expedited Process was created to enable BPA to develop preliminary ASCs under the proposed 2008 ASCM for purposes of the Residential Exchange Program (REP) cost assumptions in BPA's WP-07 Supplemental Rate Proceeding. BPA requires ASC forecasts to develop its rates. The February 7, 2008, FRN notified parties that in order to participate in the REP during FY 2009, a Pacific Northwest exchanging utility was required to notify BPA by February 22, 2008, and intervene in the Expedited Process. Exchanging utilities were required to submit the proposed 2008 ASC Appendix 1 filing template (previously referred to as the "Cookbook" template on past ASC filings) to BPA by March 3, 2008.

BPA's purpose in conducting the Expedited Process was twofold. First, BPA needed to develop forecast ASCs for its WP-07 Supplemental rate case that reflected, as closely as possible, the ASCs that would likely be in effect during the rate period (FY 2009). Because BPA had commenced a consultation process and was proposing numerous revisions to the ASCM, developing ASCs under the proposed 2008 ASCM was the most accurate way to forecast such ASCs. Second, the Expedited Process would provide BPA and its customers with valuable insight into the practical application of the proposed 2008 ASCM. Developing ASCs under the procedural and substantive terms of the proposed 2008 ASCM would give BPA and the exchanging utilities a working understanding of both the benefits and limitations of the 2008 ASCM. The experience gained through the Expedited Process could be used to identify ways to improve the proposed 2008 ASCM.

As noted above, BPA notified parties of the Expedited Process in its February 7, 2008, Federal Register Notice. *See* 73 Fed. Reg. 7270 (February 7, 2008). If a utility failed to notify BPA of its intent to participate in the REP in FY 2009 by February 29, 2008, the utility would be ineligible to receive any REP benefits during the FY 2009 rate period. Also as noted above, a utility had to file its Appendix 1 based on the proposed ASCM with BPA by March 3, 2008. BPA extended this deadline to May 7, 2008, to allow parties an opportunity to resubmit their filings in conformance with updated versions of BPA's ASC template. If a party failed to participate in the Expedited Process, BPA would rely on the Appendix 1 for the utility included by BPA in its WP-07 Supplemental Rate Proposal to determine ASCs for FY 2009.

The Expedited Process was not limited to exchanging utilities. Any interested party had the opportunity to intervene in BPA's review. Petitions to intervene were due by March 11, 2008. A total of 18 parties intervened in the process.

BPA published its final 2008 ASCM and Record of Decision on June 30, 2008. The 2008 ASCM was submitted to the Commission for its review and approval on July 7, 2008. BPA requested that the Commission grant interim approval of the 2008 ASCM no later than October 1, 2008. BPA reviewed the ASC data resulting from the Expedited Process in the context of the final version of the ASCM submitted to FERC. Where necessary, BPA adjusted the utility-filed ASC data to reflect the final version of the ASCM submitted to FERC. These adjusted ASCs are used for the Utilities' forecast ASC determinations for the final wholesale power rates for BPA's FY 2009 Final Rate Proposal. Although ASCs from the Expedited Process will be used in BPA's WP-07 Supplemental Rate Proceeding, BPA will require utilities to file new Appendix 1s with BPA on October 1, 2008. These filings will then be subject to the review process prescribed in the new ASCM and used to implement the REP for FY 2009.

The results of the Expedited Review process were incorporated into the final WP-07 Supplemental Rate Record and used in developing the final ASC forecasts for FY 2009 through FY 2013. The following sections describe the general methodology used for calculating these ASC forecasts.

8.3 Average System Cost Determination Process

The ASC forecast is calculated in a two-step process. First, a 2006 "base year" ASC is calculated for each utility. For all utilities, the base year ASC is calculated by populating BPA's 2008 ASC Appendix 1 template with financial, load, and resource cost data. For the IOUs, this data is drawn largely from 2006 FERC Form 1 filings submitted to FERC by the IOUs. Certain information from the FERC Form 1 filings for the years 2002 through 2005 was also used and will be discussed later. For the COUs, the data is based on each individual utility's 2006 annual financial reports. The process and assumptions used to develop the base year ASCs are described in more detail in Section 8.4. At the end of this first step, all of the utility's costs are functionalized between production, transmission, and distribution/other to determine the exchangeable costs. Once the exchangeable costs and loads are determined, a forecast 2006 base year ASC ($/MWh) for each utility is established.

In step two, the resulting base year ASC is escalated using the ASC Forecast Model (an Excel-based program) for each utility to FY 2009, as well as FY 2010 through FY 2013 for the 7(b)(2) rate test. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B. The processes and assumptions used in the ASC Forecast Model to escalate the base year ASC forward in time are described in Section 8.5

8.4 Base Period (2006) ASC Determination

For each utility, a 2006 base year ASC is developed using the most recently published financial and operating information. Under the 2008 ASCM, for IOUs, the base year ASC is developed using the most recent financial and load information from the utility's FERC Form 1. *See* 2008 ASCM § II.B.2., www.bpa.gov/corporate/ASCM. For COUs, the 2008 ASCM requires that the base year ASC be derived from the utility's most recent audited financial information, which must be accompanied by a cost of service analysis (COSA). *Id.*

The collected financial and operating data are entered into the 2008 ASC Appendix 1 filing template (Appendix 1), an Excel-based modeling tool. Once the data are entered, they are functionalized into the following three categories based on the proposed 2008 ASCM rules and functionalization factors: (1) Production; (2) Transmission; and (3) Distribution/Other.

The four basic cost components that were used to calculate each utility's 2006 base year ASC are: (1) rate base, which is used to determine return on rate base; (2) operating costs; (3) taxes; and (4) wholesale market revenues and other credits. These cost components, along with the system loads, are incorporated into the Appendix 1 to produce the 2006 base year ASC.

8.4.1 Exchangeable Rate Base – Base Year (2006)

The exchangeable rate base is the utility's total net plant in service, plus other allowed assets and liabilities, to which the rate of return and Federal income tax factor will be applied to determine the return on rate base and Federal income taxes to be included in exchangeable costs.

Each IOU started with the FERC Form 1 data, which has already functionalized plant and accumulated depreciation into production, transmission, distribution, and general plant. Audited financial data was used for COUs. The COUs are not required to make FERC Form 1 filings, but they do utilize the FERC Uniform System of Accounts as the basis of their financial reporting and their Appendix 1 filing. Production, transmission, and an allocation of general plant, along with accumulated depreciation, are exchangeable costs and, therefore, are included in the ASC rate base calculation. In addition to these plant accounts, the proposed 2008 ASC Methodology contains additional rules to functionalize other asset and liability accounts to Production, Transmission, and Distribution/Other.

Cash Working Capital (CWC) is another component of rate base and is typically included in almost all state regulatory commission determinations of rate base. Cash working capital is the additional capital needed to provide funds for a utility's day-to-day operations. It, however, is not a part of the FERC Form 1 filing. The 2008 ASCM uses a one-eighth of total exchangeable O&M costs, less fuel and purchase power costs, and uses it to calculate the CWC component of rate base.

8.4.2 Return on Rate Base Calculation

Rate of return (ROR) is the level of return that a utility is allowed to earn as determined by the state regulators. Public utility commissions set the rate of return based on the utility's needs to maintain service to its customers, pay adequate dividends to shareholders and interest to bondholders, and maintain and expand plant and equipment. The return on rate base is calculated in two steps. The first step is determining the cost of capital. The proposed 2008 ASCM provides that the rate of return on rate base for IOUs shall be equal to its weighted cost of capital (WCC), including debt, preferred stock, and equity, from its most recently approved State Regulatory Body Rate Order. For multi-jurisdictional utilities, a utility will first determine the WCC for each jurisdiction. The utility will then determine a regionwide WCC based on applying the WCC times the State Regulatory Body approved rate base from the same rate order used for the WCC.

The return on equity (ROE) used in the WCC calculation will then be grossed up for Federal income taxes (FIT Adder) at the marginal Federal income tax rate, using the following formula to determine the percentage increase in the ROE used for ASC determination:

FIT Adder = {(WCC) – (Cost of Debt) * (Debt / (Total Capital))} * {(Federal Tax Rate) / (1-Federal Tax Rate)}

The sum of the FIT Adder plus the ROE equals the Federal income tax adjusted ROE (TAROE). The TAROE will replace the ROE in the WCC calculation to determine a Federal income tax adjusted weighted cost of capital (TAWCC). The TAWCC will be multiplied by the total rate base from Schedule 1 to determine the return component on Schedule 2.

For COUs, the 2008 ASCM proposes that the ROR equal its weighted cost of debt. Table 8.1 shows each utility's rate of return used in the forecast.

Table 8.1
Rate of Return w/ Federal Income Tax Adder

Avista	11.173%
Idaho Power	10.945%
NorthWestern	11.196%
PacifiCorp	10.865%
Portland General	11.009%
Puget Sound Energy	10.866%
Centralia	4.650%
Franklin	4.000%
Snohomish	5.220%

Source: FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B. *See* Appendix 1 filing, Schedule 2: Capital Structure and Rate of Return for each of the exchanging utilities.

The second step is to multiply the rate base by the ROR to determine the return on rate base.

8.4.3 Operating Costs

Operating costs include operation and maintenance costs associated with generating resources, transmission plant, and an allocated portion of general plant. Operating costs are included in a utility's ASC to the extent that the operating costs are directly related to production and transmission. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B, Appendix 1 Filing, Schedule 3 Expenses for each of the exchanging utilities.

8.4.3.1 Purchased Power Costs

All purchased power costs are included in operating costs. PacifiCorp and Puget Sound Energy report REP benefits as a reduction in purchased power costs in their FERC Form 1s. Therefore, the REP values are removed from purchased power. The other IOUs do not account for REP benefits using the purchase power account. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B, Appendix 1 Filing, Schedule 3 Expenses for each of the exchanging utilities.

8.4.3.2 Depreciation and Amortization Costs

Depreciation and amortization costs are functionalized to production, transmission, or distribution costs in the same manner as their respective rate base accounts.

8.4.3.3 Administrative and General

Administrative and general (A&G) expenses are costs incurred in controlling and directing an organization, but not directly identifiable with financing, marketing, or production operations. Salaries of senior executives and costs of general services (such as accounting, contracting, and industrial relations) fall into this category. Administrative costs are related to the organization as a whole, as opposed to expenses related to individual departments. *See* 2008 ASCM, www.bpa.gov/corporate/ASCM, for the functionalization ratios used to functionalize each A&G account. *See* WPRDS Documentation, WP-07-FS-BPA-13B, Appendix 1 Filing, Schedule 3 Expenses for each of the exchanging utilities.

8.4.3.4 Taxes

8.4.3.4.1 Other Taxes

Under the proposed 2008 ASCM, property-related taxes and labor-related taxes are included as exchangeable costs. All property-related taxes were functionalized using the PTDG (a ratio incorporating production, transmission, distribution, and general plant costs). All labor-related taxes (employment and unemployment) are functionalized by using the Labor ratio. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B, and Appendix 1 Filing, Schedule 3A Items: Taxes (Including Income Taxes) for each of the exchanging utilities.

8.4.4 Wholesale Market Revenues and Other Credits

All wholesale market revenues are functionalized to production. A utility's resources are assumed to first be used to meet its load requirements and then to support its wholesale marketing activities. Other revenue accounts and revenue credits were functionalized using the following proposed functionalization rules or ratios.

Table 8.2
Revenue Credit Functionalizations

(450) Forfeited Discounts	Distribution
(451) Miscellaneous Service Revenues	Distribution
(453) Sales of Water and Water Power	Production
(454) Rent from Electric Property	TD Ratio
(455) Interdepartmental Rents	Distribution
(456) Other Electric Revenue	Production or Direct
(456.1) Revenues from Transmission of Electricity to Others	Transmission

See FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B, Appendix 1 filing, Schedule 3B Other Included Items for each of the exchanging utilities.

8.4.5 Transmission

The 2008 ASCM proposes that all transmission costs and wheeling expenses are exchangeable. All transmission revenues are credited against the exchangeable costs.

8.4.6 Oregon Public Purpose Charge

The Oregon Public Purpose Charge (OPPC) was established in 1999 with passage of Oregon's electricity restructuring law, Senate Bill 1149. *See generally,* OR. REV. STAT. § 757.612 (2005). The OPPC was established to "fund new cost-effective local energy conservation, new market transformation efforts, the above-market costs of renewable energy resources and new low-income weatherization." *Id.* at § 757.612(2)(a). The OPPC is set at 3 percent of total retail sales of electricity for PacifiCorp-Oregon and Portland General Electric. *Id*. The OPPC applies to COUs only if they allow direct access to any class of their customers. *Id.* At this time, BPA is not aware of any COUs that are participating in the OPPC program. The OPPC replaces the conservation/DSM programs Portland General and PacifiCorp operated before Oregon SB 1149. Because the OPPC funds are used to fund conservation and renewables programs, most of the OPPC will be exchangeable. *See* FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B, Appendix 1 Filing, Schedule 3 Expenses for each of the exchanging utilities.

8.4.7 PacifiCorp Inter-Jurisdictional Cost Allocation

PacifiCorp provides a unique inter-jurisdictional issue regarding the calculation of its ASC. The 2008 ASCM proposes a single ASC for each utility's entire regional load. PacifiCorp operates both inside and outside the PNW. PacifiCorp's FERC Form 1 is based on its total system, and therefore adjustments needed to be made to determine the proportion of costs that are used to serve retail load within the region. To begin, PacifiCorp's total utility cost data from the FERC Form 1 is entered into the 2008 ASC Appendix 1. To allocate PacifiCorp's total system to the region, PacifiCorp's costs are adjusted based on the Inter-Jurisdictional Cost Allocation Protocol (JCAP) developed jointly by most of PacifiCorp's state commissions. The JCAP allocates PacifiCorp's total electric system costs proportionately to each state in which it has load and regulated rates. The individual state allocation factors for the states for their corresponding accounts were entered into the 2008 ASC Appendix 1 by PacifiCorp. The total costs in each account were then multiplied by the state allocation factors to produce PacifiCorp costs by state. PacifiCorp's Idaho, Washington, and Oregon allocated costs were combined to determine regional costs. (*See* PacifiCorp's ASC forecasting model Amended_ASC_Appendix1_PAC_080822.xls at www.bpa.gov/corporate/finance/ascm/09expdrpts.cfm .)

8.4.8 New Large Single Loads

Section 3(13) of the Northwest Power Act defines an NLSL as:

> Any load associated with a new facility, an existing facility, or an expansion of an existing facility—(A) which is not contracted for, or committed to, as determined by the Administrator, by a public body, cooperative, investor-owned utility, or Federal agency customer prior to September 1, 1979, and (B) which will result in an increase in power requirements of such customer of ten average megawatts or more in any consecutive twelve-month period.

16 U.S.C. § 839(a)(13)(A)-(B).

With respect to the REP, section 5(c)(7)(A) of the Northwest Power Act precludes ASCs from including "the cost of additional resources in an amount sufficient to serve any new large single load of the utility." 16 U.S.C. § 839c(c)(7)(A). This preclusion has been reflected in BPA's 1981 and 1984 ASCMs through a prescribed treatment contained in an ASCM footnote. This treatment is continued, with modifications, in the proposed 2008 ASCM. *See* 2008 ASCM, www.bpa.gov/corporate/ASCM.

For the Expedited Process, BPA was required to make "preliminary" NLSL determinations. Each utility was required to provide historical billing data on loads that could potentially meet the requirements of an NLSL. Based on this data, BPA made preliminary "Base Period" NLSL determinations. In addition, for each of the exchanging utilities, BPA developed the estimated costs of serving an NLSL.

Transmission needed to carry power from such generation resources or power purchases was priced at the average cost of transmission during the Exchange Period.

BPA determined the Base Period cost of resources used to serve NLSLs. BPA then escalated the Base Period cost of resources used to serve NLSLs to the Exchange Period using the following steps:

i. Escalated the components of the Base Period fully allocated resource costs to the Exchange Period using the same general method for escalation of all Base Period costs.

ii. Adjusted the projected resource costs by the projected transmission costs.

iii. Added the fully allocated costs for major resource additions/retirements to the Exchange Period fully allocated costs.

iv. The cost to serve NLSLs was revised with each change to ASC to reflect the costs of the resources included in the revised ASC.

v. The quantity of Exchange Period NLSL remained constant at the Base Period NLSL amounts.

Table 8.3 shows the "preliminary" NLSL determinations for each utility for 2006, based on the proposed 2008 ASCM. For the "expedited process," only four utilities had identifiable NLSLs.

Table 8.3
2006 New Large Single Loads
(MWh)

Avista	61,449
Idaho	385,440
PacifiCorp	342,068
PGE	328,992

See FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B, Appendix 1 filing, Schedule 4 – Average System Cost for each of the exchanging utilities.

Table 8.4 shows the "preliminary" cost of resources to serve NLSLs for each utility for 2006, based on the proposed 2008 ASCM.

Table 8.4
2006 New Large Single Loads Costs
(Dollars)

Avista	$ 4,205,570
Idaho	$26,461,648
PacifiCorp	$16,964,577
PGE	$15,957,669

See FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B, Appendix 1 filing, Schedule 4 – Average System Cost for each of the exchanging utilities.

8.4.9 Contract System Costs

Contract System Costs are the utility's costs for production and transmission resources, including power purchases and conservation measures, which costs are includible in and subject to the provisions of Appendix 1 of the 2008 ASC. Contract System Costs do not include costs excluded from ASC by section 5(c)(7) of the Northwest Power Act. Contract System Costs were calculated by adding the functionalized production and transmission costs and revenue credits. Table 8.5 shows the Contract System Cost for each utility for 2006, based on the proposed 2008 ASCM.

Table 8.5
2006 Base Year Contract System Cost
(Dollars)

Avista	424,458,879
Idaho Power	467,282,700
Northwestern	332,167,038
PacifiCorp	999,811,962
Portland General	873,079,649
Puget Sound Energy	1,289,758,795
Centralia	9,269,357
Franklin	44,138,388
Snohomish	262,771,078

See FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B, Appendix 1 filing, Schedule 4 – Average System Cost for each of the exchanging utilities.

8.4.10 Contract System Loads

Contract System Load (MWh) is the denominator in the ASC calculation. System loads are a utility's total retail load, minus NLSLs, plus distribution losses. Total retail load is the total metered load a utility bills its retail customers. Distribution loss factors will vary for each utility due to the age of the utility's system and population density factors. The 2008 ASCM includes distribution losses in the Contract System Load. The ASCM states that:

> The losses shall be the distribution energy losses occurring between the transmission portion of the utility's system and the meters measuring firm energy load.

8.4.11 2006 Base Year ASC

The 2006 base year ASC for each utility is calculated in the final step of the ASC Appendix 1. This step divides the utility's Contract System Cost by the utility's Contract System Load. Table 8.6 shows the proposed 2006 base year ASC for each utility.

Table 8.6
2006 Base Year Average System Cost
(Dollars per megawatt hour)

Avista	46.21
Idaho Power	31.92
NorthWestern	53.46
PacifiCorp	46.20
Portland General	46.02
Puget Sound Energy	58.22
Centralia	37.60
Franklin	50.30
Snohomish	38.62

See WPRDS Documentation, WP-07-FS-BPA-13B, Appendix 1 filing, Schedule 4 – Average System Cost for each of the exchanging utilities.

8.5 Determination of the Exchange Period Average System Cost

After calculating the 2006 base year ASC, the next step in the ASC forecast process is to escalate the base year costs over the 2007-2013 period. To do this, the ASC Forecast Model escalates the costs of each utility, based on forecasts of escalation rates, natural gas prices, market prices of electricity, and cost of plant additions. These are described in more detail in the sections that follow. The Appendix 1 filing and respective *WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding: FY 2009 Average System Cost Report* for each exchanging utility, along with the ASC forecasting models, the off-system sales and purchased power spread model (price spread calculator) and the NLSL models, and the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding: FY 2009 Average System Cost reports for all of the exchanging utilities can be found at www.bpa.gov/corporate/finance/ascm/09expdrpts.cfm.

8.5.1 Escalation to Exchange Period

BPA escalated the "Base Period" costs to the midpoint of the fiscal year 2009 Exchange Period and the midpoint of each fiscal year for FY 2010 though FY 2013. BPA used Global Insight's forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other products. For power products purchased from BPA, BPA based the cost of these power products on BPA's forecast of prices for those products.

Table 8.7 shows the annual escalation rates used in the ASC Forecast Model. The annual gas price forecast and the annual market price forecast are explained in the Market Price Forecast Study. *See* Market Price Forecast Study, WP-07-FS-BPA-11.

Table 8.7
Escalation Rates and Price Forecasts

Cost Item	Escalation Code	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
	CONSTANT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Distribution Plant	CD	9.70%	4.60%	2.20%	1.10%	1.60%	2.00%	2.00%
Inflation	INF	2.90%	3.30%	1.40%	1.80%	1.90%	2.00%	1.90%
Wages	WAGES	3.10%	3.30%	3.30%	2.80%	3.00%	2.80%	3.00%
Steam Fuel - (Coal)	COAL	3.40%	6.70%	-2.50%	-0.40%	1.30%	1.40%	1.30%
Steam Operations	SOPS	3.50%	3.90%	1.60%	1.60%	2.00%	2.20%	2.10%
Steam Maintenance	SMN	3.00%	3.10%	1.40%	2.10%	2.00%	2.20%	2.20%
Nuclear Fuel	NFUEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Nuclear Operations	NOPS	3.00%	3.30%	2.20%	2.20%	2.00%	2.10%	2.20%
Nuclear Maintenance	NMN	6.10%	1.80%	0.90%	1.10%	1.40%	1.90%	2.10%
Hydro Operations	HOPS	3.30%	3.50%	1.40%	2.20%	1.70%	1.60%	1.60%
Hydro Maintenance	HMN	2.80%	2.60%	1.40%	1.90%	2.10%	2.10%	2.00%
Other Fuel - (Natural Gas)	NATGAS	8.07%	33.80%	-19.45%	5.28%	-2.61%	-2.78%	1.32%
Other Operations	OOPS	3.20%	3.10%	3.60%	4.60%	2.50%	1.90%	1.90%
Other Maintenance	OMN	2.90%	2.70%	1.70%	1.70%	2.00%	1.90%	2.00%
Transmission Operations	TOPS	2.60%	3.00%	3.00%	3.30%	2.10%	1.90%	2.00%
Transmission Maintenance	TMN	3.20%	3.00%	1.10%	1.10%	1.60%	2.00%	2.00%
Distribution Operations	DOPS	2.60%	3.00%	2.20%	2.30%	2.00%	2.10%	2.20%
Distributions Maintenance	DMN	3.40%	3.50%	0.80%	0.70%	1.70%	2.10%	2.10%
Customers’ Accounts	CACNT	2.20%	2.80%	2.50%	2.30%	2.00%	2.10%	2.30%
Customers’ Service	CSERV	2.80%	3.10%	2.40%	1.80%	1.30%	1.60%	2.10%
Customers’ Sales	CSALES	2.80%	3.10%	2.70%	2.40%	2.10%	2.20%	2.50%
Administrative and General	A&G	3.80%	3.70%	3.40%	3.20%	3.10%	3.10%	3.20%
New Large Single Load	NLSL	2.90%	3.30%	1.40%	1.80%	1.90%	2.00%	1.90%
Purchased Power PF (FY Esc)	PURCHPF	-6.19%	0.00%	0.00%	5.25%	0.00%	6.65%	0.00%
Purchased Power Slice (FY Esc)	PURCHSL	-6.19%	0.00%	0.00%	5.25%	0.00%	6.65%	0.00%
Purchased Power Generic #1 (FY Esc)	PURCHG1	2.90%	3.30%	1.40%	1.80%	1.90%	2.00%	1.90%
Fiscal Year Avg. Prices								
Market Price Energy	MPE	50.108	$62.89	$48.49	$49.70	$50.94	$52.22	$53.52

8.5.2 Forecast of Plant-Related Costs

8.5.2.1 Major Resource Additions and Materiality Thresholds

Under the 2008 ASCM, a utility's ASC is allowed to change during the exchange period when major new power or transmission contracts become effective or major new resource additions come on-line and are used to meet the utility's retail load. These additions include new production resource investments; new generating resource investments; new transmission investments; long-term generating contracts; pollution control and environmental compliance investments relating to generating resources, transmission resources, or contracts; hydro relicensing costs and fees; and plant rehabilitation investments. *See* 2008 ASCM § IV.C. Changes to an ASC, however, are limited to instances where the cost impact of the new resource passes a materiality threshold of an increase in ASC of 2.5 percent or greater. For the purpose of the ASC forecast, BPA assumed that any resource additions that parties indicated would be available during the exchange period would become commercially operational on the forecasted on-line date. *See* 2008 ASCM, www.bpa.gov/corporate/ASCM, for a complete description of the method used to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold.

All major new resources included in an ASC calculation prior to the start of the Exchange Period are projected forward to the midpoint of the Exchange Period. For each major new resource addition forecasted to come on-line during the Exchange Period, BPA calculates the ASC with the new resource at the midpoint of the Exchange Period.

8.5.2.2 Production and Transmission Plant

Gross production and transmission plant are held constant throughout the forecast period, unless there are production plant or transmission plant resource additions. Then a new ASC is calculated including the resource addition, as described above. *See* Section 8.5.2.1.

Table 8.8 shows the "base" rate period ASC (before additions) and the incremental changes in the ASC that would occur as PacifiCorp's projected new resource additions come on-line.

Table 8.8
PacifiCorp
Base ASC & ASC Deltas
($/MWh)

Base ASC	$47.98
Lake Side Capitol Building	$0.83
Group 1	$1.26
CCCT Plant West	$0.33
Group 3	$0.93
Group 4	$0.48

As per the 2008 ASCM, exchanging utilities can group resources that meet the materiality threshold. PacifiCorp had three resource groups. See 2008 ASCM, www.bpa.gov/corporate/ASCM, for a complete description of the method to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold.

Source: FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B, Table 20k.

Table 8.9 shows the "base" rate period ASC (before additions) and the incremental changes in the ASC that would occur as PGE's projected new resource additions come on-line.

Table 8.9
PGE
Base ASC & ASC Deltas
($/MWh)

Base ASC	$50.49
Port Westward	$3.13
Biglow Canyon	$1.37
Selective Water Withdrawal	$0.60
Biglow Canyon 2	$1.94

Source: FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B, Table 21k.

Avista, Centralia, Franklin, NorthWestern, PSE, and Snohomish did not submit any new resource additions. Idaho submitted a major resource addition that was post-2006 and already on-line, so the costs are included in Idaho's 2009 ASC.

8.5.2.3 Forecasted Distribution Plant-Related Costs

Distribution plant is used to calculate some of the functionalization ratios used in the calculation of a utility's ASC. Therefore, BPA escalated the Base Period average per-MWh cost of Distribution Plant forward to the midpoint of the Exchange Period, and used the escalated average cost to determine the distribution plant-related cost of meeting load growth since the Base Period. This cost was then included in the ratios used to forecast the FY 2009 through FY 2013 ASCs.

8.5.2.4 Forecasted General Plant-Related Costs

To escalate General Plant-related costs, BPA first calculated the ratio of "Base Period" General Plant to the sum of Base Period Production, Transmission, and Distribution plant. BPA then applied this Base Period ratio to the sum of the forecasted gross costs of Production, Transmission, and Distribution plant.

8.5.3 Rate of Return Forecast

The rate of return is held constant at the 2006 value for the entire forecast period.

8.5.4 Depreciation and Amortization Forecast

Depreciation and Amortization expense for each account is forecasted to be constant, except for additional depreciation expenses associated with the following:

- new plant additions
- new distribution plant additions associated with load growth (depreciation additions is equal to the additional gross distribution plant times the ratio of the 2006 distribution depreciation to the 2006 gross distribution plant)
- new general plant

8.5.5 Tax Forecast

8.5.5.1 State and Local Tax Forecast

Property-related taxes are held constant throughout the forecast period unless there are property taxes identified with major resource additions. Labor-related taxes are escalated using the wages escalator.

8.5.6 Forecasted Contract System Load and Exchange Load

Each utility was required to provide a forecast of its Contract System Load and associated Exchange Load, as well as a current distribution loss study as described in endnote e/ of the 2008 Average system Cost Methodology, with its Appendix 1 filing. The load forecast for Contract System Load and Exchange Load starts with the Base Period and extends through four years after the Exchange Period.

8.5.7 Forecast Methodology for Meeting Load Growth

All forecast load growth will first be met by new resource additions. If the new resource is less than total forecast load growth, the unmet load growth will be supplied with market purchases priced at the utility's forecasted short-term purchased power price. In the event that the power provided by a new resource exceeds the utility's forecast load growth, the excess will be sold as surplus power into the market and priced at the utility's forecast sales for resale price as determined by BPA in section 8.5.8.

8.5.8 Treatment of Sales for Resale and Power Purchases

The ASC Forecast Model distinguishes between long-term and short-term purchased power. In the FERC Form 1, utilities separate purchased power and sales for resale by the type and length of the purchase and also report any adjustments. The COUs were required to provide detailed information on their long-term, intermediate-term, and short-term purchased power costs and sales for resale revenues.

BPA escalated the long-term and intermediate-term (as defined by FERC) firm purchased power costs and sales for resale revenues at the rate of inflation.

For short-term purchases and sales for resale revenues, the short-term purchases and sales for resale revenues for the Base Period were used as starting values. Each utility's ASC was adjusted to reflect new plant additions and used a utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue to be included in the Rate Period ASC.

BPA used each utility's historical three-year weighted spread between short-term purchased power price and sales for resale price to determine that utility's forecasted relationship between forecasted short-term purchased power and sales for resale prices to calculate Exchange Period ASCs. (*See* proposed 2008 ASCM, www.bpa.gov/corporate/ASCM, for a complete description of the method to determine separate market prices to forecast short-term purchased power expense and sales for resale revenues.) Centralia reported no 2006 sales for resale; therefore, the spread was set to zero. Franklin and Snohomish reported purchased power and sales for resale only for the base year, so BPA used only the one-year (2006) spread. There were anomalies in PacifiCorp's 2004 and 2005 reported purchased power and sales for resale data. BPA therefore used the one-year (2006) spread.

To forecast a utility's short-term purchased power and sales for resale price, BPA first calculated the midpoint of the utility's 2006 average short-term purchased power and sales for resale price. BPA then escalated the midpoint at the same rate as BPA's market price forecast. The weighted average spread was then applied to the forecasted midpoint to determine the forecasted purchased power and sales for resale price.

8.5.9 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. *See* Section 8.5.8.

The ASC forecast assumed that the quantity of long-term and intermediate-term firm sales is constant for 2007-2013 and that sales revenue escalates at the rate of inflation.

The short-term sales are forecast to be constant into the future unless a utility's forecast resource additions exceed the utility's forecast load growth requirements and reduce short-term purchased power to zero. In such case, the surplus energy is sold off-system at the forecast short-term sales for resale price as determined by BPA in section 8.5.8.

8.5.10 Other Revenues

Wheeling revenues are held constant unless there are new transmission additions. The increase in wheeling revenues resulting from new transmission resource additions equals:

(The wheeling revenues (before additions) / net transmission plant (before additions)) * new transmission additions.

Other Revenues are forecast to be constant through the rate period.

8.5.11 New Large Single Load

BPA conducted a preliminary NLSL determination as part of the expedited ASC process. Potential NLSLs were identified for Avista, Idaho, PacifiCorp, and PGE. Table 8.10 provides the NLSL loads excluded from the ASC calculation. The NLSL loads were forecast to be constant through the rate period and 7(b)(2) period. Table 8.11 provides the forecast NLSL costs excluded from the ASC calculation.

Table 8.10
New Large Single Loads
(MWh)

Avista	61,449
Idaho	385,440
PacifiCorp	342,068
PGE	328,992

Source: FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B, Avista Table 15k Forecasted Contract System Costs & ASC with New Additions and NLSL; Idaho Table 18k Forecasted Contract System Costs & ASC with New Additions and NLSL; PacifiCorp Table 20k Forecasted Contract System Costs & ASC with New Additions and NLSL; and PGE Table 21k Forecasted Contract System Costs & ASC with New Additions and NLSL.

Table 8.11
New Large Single Load Costs
(Dollars)

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Avista	4,771,005	4,416,922	4,446,260	4,361,813	4,298,313
Idaho	30,492,835	29,297,863	29,244,354	29,086,338	28,938,635
PacifiCorp	19,865,032	19,078,938	19,052,436	18,876,147	18,726,097
PGE	24,127,751	22,847,185	22,864,160	22,628,883	22,365,495

Source: FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B, Avista Table 15k Forecasted Contract System Costs & ASC with New Additions and NLSL; Idaho Table 18k Forecasted Contract System Costs & ASC with New Additions and NLSL; PacifiCorp Table 20k Forecasted Contract System Costs & ASC with New Additions and NLSL; and PGE Table 21k Forecasted Contract System Costs & ASC with New Additions and NLSL.

8.5.12 Forecast Contract System Costs, Contract System Load, and Average System Cost

8.5.12.1 Contract System Cost Forecasts

The ASC Forecast Model calculates Contract System Costs as follows:

$$\text{Exchange Cost}_{2009} = \Sigma \text{ Rate Base Accounts} \times (1+ \text{escalator}_{\text{(by account)}}) \times \text{ROR}$$

$$(\text{w/ Federal Income Tax Factor})$$

$$+ (\Sigma \text{ Expense Accounts}_{\text{(by account)}}) \times (1+ \text{escalator}_{\text{(by account)}})$$

$$+ \text{Wholesale Purchase Expense}_{2009}$$

$$- \text{Wholesale Sales for Resale Revenue Credit}_{2009}$$

$$+ \text{Cost of Load Growth}$$

$$- \text{New Large Single Load Cost}$$

The COU forecasts do not include the Federal income tax calculation. Summaries of the individual utility ASC forecasts are shown in the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B.

Table 8.12 provides the forecast Contract System Costs by utility, assuming all projected new resources come on-line.

Table 8.12
Forecast Contract System Costs
(Millions of dollars)

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Avista	481.8	473.5	484.2	492.3	500.9
Centralia	10.3	10.9	11.2	12.0	12.3
Franklin	46.8	49.8	50.3	54.1	54.6
Idaho	534.0	545.3	559.8	568.1	580.7
NorthWestern	375.4	391.4	409.3	428.7	449.5
PacifiCorp	1,153.7	1,115.8	1,122.3	1,121.8	1,124.3
PGE	1,079.8	1,074.7	1,107.1	1,131.8	1,160.3
PSE	1,374.7	1,386.8	1,411.8	1,434.3	1,458.1
Snohomish	277.4	292.7	296.5	313.5	317.4

Source: FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B, Table 2 Total Contract System Cost.

8.5.12.2 Total Retail Load and Contract System Load Forecasts

"Base Year" Contract System Load is discussed in Section 8.1.1.10. Each exchanging utility was required to provide forecast total retail load for 2007-2013. Table 8.13 shows the forecast Contract System Load for each of the exchanging utilities.

Table 8.13
Forecast Contract System Load
(Gigawatt-hours)

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Avista	9,582	9,778	9,946	10,157	10,348
Centralia	291	298	305	313	321
Franklin	1,023	1,047	1,065	1,082	1,101
Idaho	15,772	16,059	16,300	16,422	16,596
NorthWestern	6,845	7,070	7,301	7,541	7,788
PacifiCorp	22,264	22,461	22,686	22,919	23,151
PGE	18,769	19,189	19,618	20,057	20,505
PSE	23,022	23,222	23,391	23,545	23,687
Snohomish	7,284	7,386	7,447	7,508	7,562

Source: FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B, Table 3 Contract System Load.

8.5.12.3 Forecast Average System Cost

Table 8.14 shows the resulting forecast ASCs for the exchanging utilities, including all new resource additions.

Table 8.14
Forecast Average System Costs
(Dollars per Megawatt-hour)

	4/1/2009	4/1/2010	4/1/2011	4/1/2012	4/1/2013
Avista	50.28	48.42	48.69	48.47	48.41
Centralia	35.56	36.71	36.68	38.27	38.26
Franklin	45.74	47.59	47.24	50.01	49.62
Idaho	33.86	33.96	34.34	34.60	34.99
NorthWestern	54.84	55.36	56.06	56.85	57.72
PacifiCorp	51.82	49.68	49.47	48.95	48.56
PGE	57.53	56.01	56.43	56.43	56.59
PSE	59.71	59.72	60.36	60.92	61.56
Snohomish	38.08	39.63	39.81	41.76	41.97

Source: FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B, Table 1 Average System Cost $/MWh.

8.5.12.4 Average System Cost Forecast for 7(b)(2) Rate Test

Table 8.15 shows the resulting forecast ASCs for the exchanging utilities that were used in the 7(b)(2) rate test. PacifiCorp and PGE both have new resources coming on-line during the rate period, so their forecast FY 2009 ASCs change with each new resource. Therefore, the FY 2009 ASCs for PacifiCorp and PGE are weighted averages based on the number of months that the ASCs will be in effect.

Table 8.15
Average System Cost Forecast for 7(b)(2) Rate Test
(Dollars per megawatt-hour)

				FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Avista				50.28	48.42	48.69	48.47	48.41
Centralia				35.56	36.71	36.68	38.27	38.26
Franklin				45.74	47.59	47.24	50.01	49.62
Idaho				33.86	33.96	34.34	34.60	34.99
Northwestern				54.84	55.36	56.06	56.85	57.72
	10/1/2008	**1/1/2009**	**6/1/2009**					
PacifiCorp	50.40	51.34	51.82	51.27	49.68	49.47	48.95	48.56
	10/1/2008	**4/1/2009**	**8/1/2009**					
PGE	54.99	55.59	57.53	55.61	56.01	56.43	56.43	56.59
PSE				59.71	59.72	60.36	60.92	61.56
Snohomish				38.08	39.63	39.81	41.76	41.97

9. SLICE OF THE SYSTEM (SLICE) PRODUCT, SLICE REVENUE REQUIREMENT, AND SLICE RATE

9.1 Explanation of Changes

This chapter reflects changes to the Slice True-Up process and changes to 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 Northwest Requirements Utilities on November 22, 2006. In addition, this section reflects the impact on the Slice Revenue Requirement that result from decisions by the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) regarding the 2000 REP Settlement Agreements (REP Settlement Agreements).

This section also explains changes to the Slice Revenue Requirement for FY 2009 and changes to the Methodology to Calculate Slice Rate and Slice True-Up Adjustment Charge (Slice Rate Methodology). *See* 2007 Wholesale Power Rate Schedules (FY 2009) and FY 2007 General Rate Schedule Provisions (FY 2009), WP-07-A-BPA-05A, Appendix A.

9.2 Slice Product Description

The Slice product is a sale of a fixed percentage of the generation output of the Federal Columbia River Power System (FCRPS). It is not a sale or lease of any part of the ownership of, or operational rights to, the FCRPS. The Slice product is a power sale based upon a Slice customer's annual net firm requirement load and is shaped to BPA's generation output from the FCRPS. BPA's Subscription sale of the Slice product required a commitment by each Slice customer to purchase the product for 10 years, from FY 2002 through FY 2011.

Because the Slice product is calculated as a percentage of the FCRPS generation output, the actual amount of 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 requirement and may, at times, exceed the Slice customer's actual firm load. As a consequence, the Slice product entails a sale of both requirements power and surplus power.

9.3 Slice Revenue Requirement

Each Slice customer pays a percentage of BPA's costs, rather than a set price per megawatt and megawatt-hour. The Slice customer's obligation to pay is based on the percentage of the FCRPS generation output the Slice customer elected to purchase in its 10-year Subscription contract. The Slice customers pay a percentage of the Slice Revenue Requirement. The Slice Revenue Requirement is comprised of all of the line items in BPA's power revenue requirement, with certain limited exceptions. *See* Table 9.1 below, Slice Product Costing and True-Up Table, 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, et al. v. Bonneville Power Administration*, No. 03-73849, *Northwest Requirements Utilities v. Bonneville Power Administration,* No. 04-71311, and *Benton County PUD, et al. v. Bonneville Power Administration,* No. 03-74179. In July 2006, BPA, the Slice customers, and Northwest Requirements Utilities agreed on a settlement of the issues. 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 provided for refunds to Slice customers in the form of credits to their bills that settled disputes related to the Slice True-Up Adjustment Charges for FY 2002-2005. It also included a new dispute resolution provision and a Memorandum of Understanding regarding BPA's Debt Optimization Program.

In this WP-07 Supplemental Final Proposal, BPA is modifying the rate treatment of certain Slice rate and Slice Rate Methodology matters to be consistent with the Slice Settlement. *See* Johnson, *et al.,* WP-07-E-BPA-59**.**

9.4 Inclusion and Treatment of Expenses and Revenue Credits

BPA made changes to the treatment of particular expenses and revenue credits in the Slice Revenue Requirement for FY 2009 and Slice True-Up for FY 2009, 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 (augmentation, defined in Section 5.2.3.3); (2) inter-business line transmission costs except those associated with serving BPA system obligations and GTAs (defined in Section 4); and (3) PNRR (or its successor risk mitigation tools, defined in Section 3.2.5.3.3) 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 2009. The expenses and revenue credits included in the Slice Revenue Requirement that is the basis for the FY 2009 Slice rate are forecasts for FY 2007-2009 that are included in the WP-07

Supplemental Final Proposal. The Actual Slice Revenue Requirement will include the same expense and revenue credit categories as the Slice Revenue Requirement, but will be 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 9.6 for a more detailed description of the Slice True-Up process.

9.4.1 Augmentation Expenses

During the prior rate period (FY 2002-2006), BPA supplemented (augmented) the capability of the Federal system to meet the total load placed on BPA. These augmentation power purchases were those needed to meet all load service requests made under BPA's Subscription contracts on a planning basis. For ratemaking purposes, augmentation purchases are considered to be separate and distinct from balancing purchases. *See* Section 3.2.1.2.2. 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 at the PF Preference rate. 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. This WP-07 Supplemental Final Proposal revises the forecast of augmentation expenses for FY 2009. BPA identified three distinct types of augmentation expenses for FY 2007-2009: (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 FY 2002-2006 into FY 2007-2009. When BPA purchased power to meet its load obligations for FY 2002-2006, some of the purchases extended to the end of calendar year 2006, three months into the WP-07 rate period. The energy associated with the residual augmentation purchases will be used to meet BPA's load obligations in 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 purchased 105 aMW of residual augmentation power, for a total of $49 million in FY 2007. *See* 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 Preference multiplied by the amount of residual augmentation power, which was 105 aMW in FY 2007. The average PF rate determined in the WP-07 Final Proposal was 27.33 mills/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) into FY 2007-2011. With accrued interest, this totaled $115 million of deferred augmentation expenses for FY 2007-2011, which was sought to be recovered through WP-07 rates in amounts of $23 million per year. *See* Table 9.1, Slice Product Costing and True-Up Table.

As the result of a series of recent decisions by the Ninth Circuit, BPA will revise the forecast of the deferred augmentation expense for FY 2009. *See* Bliven, *et al.*, WP-07-E-BPA-52. This WP-07 Supplemental Final Proposal revises this deferred augmentation expense for FY 2009, but this revision will not affect the Slice Revenue Requirement for FY 2007-2008. BPA has forecast this expense to be zero in the Slice Revenue Requirement for FY 2009.

The third category of expenses is "other" augmentation expenses. This category includes the expenses associated with augmentation purchases that BPA needs to meet its load obligation during FY 2007-2009. In the WP-07 Final Proposal, BPA forecast the augmentation amounts for FY 2007, 2008, and 2009 to be 179 aMW, 179 aMW, and 270 aMW, respectively. *See* Load Resource Study, WP-07-FS-BPA-01, at 60. This WP-07 Supplemental Final Proposal revises the forecast of augmentation need in FY 2009 to a total of 313 aMW. *See* Section 5.2.3.3. In FY 2009, Slice customers will pay their proportionate share of the "net cost" of these augmentation purchases. In this WP-07 Supplemental Final Proposal, the revised forecast augmentation purchase prices for FY 2009 are 60.20 mills/kWh for 299 aMW of unspecified augmentation and 28.30 mills/kWh for 13.4 aMW of ERE purchased from Slice customers. *Id.* The revenues associated with the sale of augmentation power are estimated, based on the projected PF Preference rate for power and multiplied by the amount of power that would be sold (179 aMW, 179 aMW, and 313 aMW, respectively for FY 2007, 2008, and 2009). The PF Preference rate is 27.33 mills/kWh for FY 2007 and 2008, and 26.82 mills/kWh for FY 2009. BPA subtracts the expected revenues from the forecast purchase expense to calculate the net cost of the augmentation purchases for FY 2007-2009. The net cost of augmentation power for FY 2007-2009 will not be subject to the Slice True-Up process.

9.4.2 Conservation Augmentation (ConAug)

Conservation Augmentation (ConAug) was the conservation component of BPA's inventory solution in the WP-02 Final Proposal. 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 FY 2002-2006. The cost of this power was estimated to be 28.1 mills/kWh plus 10 percent, or 30.9 mills/kWh, and was included as part of the Slice Revenue Requirement.

In the WP-02 Final Proposal, 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 FY 2002-2006. Slice customers paid their share of the estimated costs of 100 aMW of ConAug during FY 2002-2006. If BPA acquired more than 20 aMW during any given year, those costs would be handled through Load-Based Cost Recovery Adjustment Clause (LB CRAC) and included in related charges to both Slice and non-Slice customers.

BPA decided to capitalize the costs of actual ConAug acquisitions subsequent to the WP-07 Final Proposal. As a result there are annual amortization expenses associated with ConAug investments from FY 2002-2006 that carry over into FY 2007-2009. *See* Revenue Requirement Study Documentation, Vol. 1, 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 2011. However, Slice customers will not pay for these ConAug amortization costs in the FY 2009 because Slice customers paid a forecast of ConAug costs as if they were incurred as annual expenses. Therefore, the amortization is excluded from the Slice Revenue Requirement and the Actual Slice Revenue Requirement.

9.4.3 IOU Residential Exchange Program (REP) Settlement Benefits

In the WP-07 Final Proposal, Slice customers were obligated to pay their proportionate share of the benefits payments under the IOU REP settlements during FY 2007-2009. The REP settlements are now proposed to be removed from consideration in ratemaking. *See* Bliven, *et al.*, WP-07-E-BPA-52. Therefore, the costs of the REP settlements are proposed to be removed from the Slice Revenue Requirement. This WP-07 Supplemental Final Proposal will result in a restart of the REP beginning October 1, 2008. Consistent with the Slice Rate Methodology, the net costs of REP benefits (gross exchange costs minus gross PF Exchange rate revenues) will be included in the Slice Revenue Requirement.

9.4.4 Cost of the Residential Exchange for COUs

Slice customers are responsible for paying their proportionate share of the net cost of the REP benefits for COUs. The net cost of the REP benefits for COUs is calculated by subtracting the gross exchange revenues from the gross exchange expenses. An amount of net costs of the REP for public utilities was forecast for each year of FY 2007-2009 and included in the Slice Revenue

Requirement. The actual costs of the REP for COUs in any year will be included in the Actual Slice Revenue Requirement for that year, for purposes of calculating the Slice True-Up.

9.4.5 Bad Debt Expense

The Slice Revenue Requirement contains 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 are forecast for bad debt expense for FY 2009, the Actual Slice Revenue Requirement may contain an 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. *See* Evans, *et al.*, WP-07-E-BPA-31, Attachment A. However, any bad debt expense associated with the sale of energy under both the PF-07R and FPS-07R, or just the PF-07R rate schedule, will be included in the Actual Slice Revenue Requirement for Slice True-Up purposes. *Id.*, at A-4. Through the annual Slice True-Up, Slice customers will pay 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). 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 credit for recovery of any related outstanding receivables 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. Slice customers will not receive credit for recovery of receivables that BPA collects from DSIs.

9.4.6 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 FY 2007-2011. *See* Gustafson*, et al.,* WP-07-E-BPA-17. These costs are included in the Slice Revenue Requirement and will be subject to the annual Slice True-Up. Slice customers will pay their proportionate share of these costs.

9.4.7 Fish and Wildlife Program Costs

Slice customers are obligated to pay their proportionate share of BPA's 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 will also experience 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 differ from the forecasts contained in the Slice Revenue Requirement, Slice customers will pay their proportionate share of any increase or decrease in fish and wildlife annual expenses through their annual True-Up. Slice customers would be 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 subject to neither the National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) (NFB) Adjustment nor the Emergency NFB Surcharge. As already mentioned, Slice customers pay their proportionate share of any changes in fish and wildlife annual expenses through their annual True-Up, and any indirect program cost changes are experienced through changes in Slice power deliveries.

9.4.8 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 solely 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 Power Sales Agreement 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 the WP-07 Final Proposal, where all Slice Computer Application Project costs were accounted for as expenses instead of capital costs.

Projections of Slice Implementation Expenses are not included in the Slice Revenue Requirement, and therefore are not included in the Slice rate for FY 2009. Slice Implementation

Expenses in any given Contract Year will be accounted for after the audited year-end Actual Slice Revenue Requirement for that Contract Year is available. Slice Implementation Expenses will be charged to Slice customers through the annual Slice True-Up for that Contract Year.

9.4.9 Debt Optimization Program

Through the Debt Optimization Program, BPA refinances (*i.e.*, extends the maturities of) Energy Northwest bonds as they come due and repays an equivalent amount of Federal debt. In total, the same amount of debt is repaid as scheduled through the rate setting process, but with an emphasis toward repaying Federal debt rather than non-Federal debt. *See* FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10, section 1.2.

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 not only affects the Slice rate (through the annual True-Up Adjustment Charge), but is a recognized factor of BPA's rates 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.

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

BPA will reinvest 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 come from three sources: (1) Green Energy Premium revenues resulting from sales of

Environmentally Preferred Power (EPP); (2) Green Tag revenues resulting from sales of Renewable Energy Certificates (RECs); and (3) revenues from sales of Alternative Renewable Energy (ARE) to Pre-Subscription power purchasers. BPA will 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* Evans, *et al.*, WP-07-E-BPA-31, Attachment A, Partial Resolution of Issues.

9.4.11 Minimum Required Net Revenues Calculation

Minimum Required Net Revenues (MRNR) is a component of the annual Generation Revenue Requirement. *See* FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10, section 4.1.2. MRNR also is a component of the Slice Revenue Requirement. 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 in the MRNR 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 MRNR 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* FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10, section 4.1.2. 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 are not relevant to cost recovery for Slice and do not appear in the calculation of MRNR for the Slice Revenue Requirement (which is represented by the Slice Product Costing and True-Up Table). Due to this difference, the MRNR in the Slice Product Costing and True-Up Table, is smaller than the MRNR in the total power revenue requirement.

9.5 Slice Rate

The Slice Revenue Requirement is the basis for calculating the base Slice rate. To calculate the Slice rate for FY 2009, the total dollar amounts for each fiscal year of the Slice Revenue Requirement in this WP-07 Supplemental Final Proposal are summed and divided by 36 months (the number of months in the three-year rate period FY 2007-2009) and divided by 100 to obtain the base Slice rate per percent of Slice product purchased. *See* Table 9.1, Slice Product Costing and True-Up Table. The monthly Slice rate for FY 2009 is $1,872,639 per one percent Slice product purchased.

9.6 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, 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 true-up calculation will result in an additional charge or credit to the Slice customer. This additional charge or credit to the Slice customer is known as the Slice True-Up Adjustment Charge (or Credit). Because of the Slice True-Up Adjustment Charge (or Credit), Slice customers pay 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 adverse or beneficial conditions change BPA's financial condition. The Slice customers' payments through their base Slice rate and the annual True-Up Adjustment Charge mitigate 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 are assumed directly by the Slice customers.

9.7 Changes to the Methodology to Calculate Slice Rate and Slice True-Up Adjustment Charge

BPA is proposing to make several minor updates to the Slice Rate Methodology to avoid confusion during FY 2009. These updates are intended to account for changes in circumstances since the Slice Rate Methodology was initially established and are not intended to materially change the Slice Rate Methodology. The proposed updates include changes that make the Slice Rate Methodology consistent with the provisions of the Slice Settlement. *See* Lee, *et al.*, WP-07-E-BPA-74.

Table 9.1, Slice Product and Costing 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	$ 293,700
5	BUREAU OF RECLAMATION		$ 71,654	$ 74,760	$ 82,100
6	CORPS OF ENGINEERS		$ 161,519	$ 165,742	$ 179,500
7	LONG-TERM CONTRACT GENERATING PROJECTS		$ 24,932	$ 25,314	$ 31,522
8	**Sub-Total**		**$ 521,774**	**$ 454,504**	**$ 586,822**
9	**Operating Generation Settlement Payment**				
10	COLVILLE GENERATION SETTLEMENT		$ 16,968	$ 17,354	$ 20,909
11	SPOKANE GENERATION SETTLEMENT		$ -	$ -	$ -
12	**Sub-Total**		**$ 16,968**	**$ 17,354**	**$ 20,909**
13	**Non-Operating Generation**				
14	TROJAN DECOMISSIONING		$ 5,400	$ 4,700	$ 2,500
15	WNP-1&3 DECOMISSIONING		$ 200	$ 200	$ 400
16	**Sub-Total**		**$ 5,600**	**$ 4,900**	**$ 2,900**
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	$ 54,999
21	OTHER POWER PURCHASES (short term - omit)				
22	**Sub-Total**		**$ 60,714**	**$ 60,714**	**$ 56,713**
23	**Augmentation Power Purchases**				
24	AUGMENTATION POWER PURCHASES (omit - calculated below)				
25	CONSERVATION AUGMENTATION (omit)				
26	PUBLIC RESIDENTIAL EXCHANGE (net costs)		**$ 6,762**	**$ 6,811**	**$ 1,107**
27	IOU RESIDENTIAL EXCHANGE		**$ 301,000**	**$ 301,000**	**$ 251,161**
28	**Renewable Generation (expenses related to reinvestment removed)**		**$ 30,289**	**$ 34,719**	**$ 41,050**
29	**Generation Conservation**				
30	LOW INCOME WEATHERIZATION & TRIBAL		$ 5,000	$ 5,000	$ 5,812
31	ENERGY EFFICIENCY DEVELOPMENT		$ 12,885	$ 12,908	$ 22,000
32	ENERGY WEB		$ 1,000	$ 1,000	$ 7,000
33	**LEGACY (Until 11/1/03 this was included with line 72)**		$ 3,728	$ 2,638	$ 2,114
34	MARKET TRANSFORMATION		$ 10,000	$ 10,000	$ 10,000
35	TECHNOLOGY LEADERSHIP		$ 1,300	$ 1,300	$ 1,600
36	INFRASTRUCTURE SUPPORT AND EVALUATION		$ 1,000	$ 1,000	
37	BI-LATERAL CONTRACT ACTIVITY		$ 1,000	$ 1,000	
38	**Sub-Total**		**$ 35,913**	**$ 34,846**	**$ 48,526**
39	CONSERVATION RATE CREDIT		$ 36,000	$ 36,000	$ 32,000
40	**Power System Generation Sub-Total**		**$ 1,015,019**	**$ 950,848**	**$ 1,041,188**
41					
42	**PBL Transmission Acquisition and Ancillary Services**				
43	**PBL Transmission Acquisition and Ancillary Services**				
44	PBL - TRANSMISSION & ANCILLARY SERVICES				
45	Canadian Entitlement Agreement Transmission Expenses		$ 24,806	$ 25,550	$ 27,000
46	PNCA & NTS Transmission and System Obligaton Expenses		$ 1,775	$ 1,825	$ 1,000
47	3RD PARTY GTA WHEELING		$ 47,000	$ 47,000	$ 50,370
48	PBL - 3RD PARTY TRANS & ANCILLARY SVCS				$ -
49	RESERVE & OTHER SERVICES		$ 8,462	$ 8,462	$ 6,800
50	TELEMETERING/EQUIP REPLACEMT		$ 200	$ 200	$ 50
51	**PBL Trans Acquisition and Ancillary Services Sub-Total**		**$ 82,243**	**$ 83,037**	**$ 85,220**
52					
53	**Power Non-Generation Operations**				
54	**PBL System Operations**				
55	EFFICIENCIES PROGRAM (omit TMS expenses)		$ -	$ -	$ 5,423
56	INFORMATION TECHNOLOGY		$ -	$ -	$ -
57	GENERATION PROJECT COORDINATION		$ 5,637	$ 5,738	$ 7,648
58	SLICE IMPLEMENTATION (omit - calculated separately)				
59	**Sub-Total**		**$ 5,637**	**$ 5,738**	**$ 13,071**
60	**PBL Scheduling**				
61	OPERATIONS SCHEDULING		$ 8,758	$ 9,051	$ 9,571
62	OPERATIONS PLANNING		$ 5,202	$ 5,358	$ 5,969
63	**Sub-Total**		**$ 13,960**	**$ 14,409**	**$ 15,540**
64	**PBL Marketing and Business Support**				
65	SALES & SUPPORT		$ 15,884	$ 16,278	$ 18,988
66	Contractual exclusion		$ (5,360)	$ (5,360)	$ (5,360)
67	Implementation Expense Exclusions - Add back				
68	PUBLIC COMMUNICATION & TRIBAL LIAISON				
69	STRATEGY, FINANCE & RISK MGMT		$ 10,965	$ 11,359	$ 14,820
70	EXECUTIVE AND ADMINISTRATIVE SERVICES		$ 845	$ 840	$ 3,123
71	CONSERVATION SUPPORT (EE staff costs)		$ 6,441	$ 6,692	$ 7,996
72	**Sub-Total**		**$ 28,776**	**$ 29,808**	**$ 39,567**
73	**Power Non-Generation Operations Sub-Total**		**$ 48,372**	**$ 49,955**	**$ 68,178**
74					
75	**Fish and Wildlife/USF&W/Planning Council**				
76	**BPA Fish and Wildlife (includes F&W Shared Services)**				
77	FISH & WILDLIFE		$ 143,000	$ 143,000	$ 199,998
78	F&W HIGH PRIORITY ACTION PROJECTS				
79	**Sub-Total**		**$ 143,000**	**$ 143,000**	**$ 199,998**
80	**PBL-USF&W Lower Snake Hatcheries**				
81	USF&W LOWER SNAKE HATCHERIES		$ 18,600	$ 19,500	$ 19,690
82	**PBL - Planning Council**				
83	PLANNING COUNCIL		$ 9,085	$ 9,276	$ 9,450
84	**PBL - ENVIRONMENTAL REQUIREMENTS**				
85	ENVIRONMENTAL REQUIREMENTS		$ 500	$ 500	$ 300
86	**Fish and Wildlife/USF&W/Planning Council Sub-Total**		**$ 171,185**	**$ 172,276**	**$ 229,438**

Table 9.1, continued, Slice Product and Costing Table

87					
88	**BPA Internal Support**				
89	**CSRS/FERS**				
90	ADDITIONAL POST-RETIREMENT CONTRIBUTION	$ 10,550	$ 9,000	$ 15,277	
91	**Corporate Support - G&A (excludes direct project support)**				
92	CORPORATE G&A	$ 50,247	$ 51,753	$ 44,994	
93	**TBL Supply Chain - Shared Services**	$ 368	$ 374		
94	**General and Administrative/Shared Services Sub-Total**	**$ 61,165**	**$ 61,127**	**$ 60,271**	
95					
96	**Bad Debt Expense**				
97	**Other Income, Expenses, Adjustments**	**$ 1,800**	**$ 1,800**	**$ -**	
98	**Non-Federal Debt Service**				
99	**Energy Northwest Debt Service**				
100	COLUMBIA GENERATING STATION DEBT SVC	$ 195,690	$ 217,856	$ 224,801	
101	WNP-1 DEBT SVC	$ 147,941	$ 165,916	$ 169,509	
102	WNP-3 DEBT SVC	$ 151,724	$ 160,092	$ 150,983	
103	EN RETIRED DEBT				
104	EN LIBOR INTEREST RATE SWAP				
105	**Sub-Total**	**$ 495,355**	**$ 543,864**	**$ 545,293**	
106	**Non-Energy Northwest Debt Service**				
107	TROJAN DEBT SVC	$ 8,605	$ 7,888	$ -	
108	CONSERVATION DEBT SVC	$ 5,203	$ 5,198	$ 5,188	
109	COWLITZ FALLS DEBT SVC	$ 11,619	$ 11,583	$ 11,571	
110	WASCO DEBT SVC	$ -	$ 1,664	$ 2,168	
111	**Sub-Total**	**$ 25,427**	**$ 26,333**	**$ 18,927**	
112	**Non-Federal Debt Service Sub-Total**				
113	Depreciation (excl. TMS)	$ 118,058	$ 121,829	$ 118,832	
114	Amortization (excludes ConAug amortization)	$ 55,567	$ 60,241	$ 56,412	
115	**Total Operating Expenses**	**$ 2,074,191**	**$ 2,071,310**	**$ 2,223,759**	
116					
117	**Other Expenses**				
118	Net Interest Expense	$ 163,080	$ 173,193	$ 160,845	
119	LDD	$ 22,289	$ 22,612	$ 25,219	
120	Irrigation Rate Mitigation Costs	$ 10,000	$ 10,000	$ 12,000	
121	**Sub-Total**	**$ 195,369**	**$ 205,805**	**$ 198,064**	
122	**Total Expenses**	**$ 2,269,560**	**$ 2,277,115**	**$ 2,421,823**	
123					
124	**Revenue Credits**				
125	Ancillary and Reserve Service Revs. Total	$ 73,131	$ 61,970	$ 79,306	
126	Downstream Benefits and Pumping Power	$ 8,921	$ 8,921	$ 8,921	
127	4(h)(10)(c)	$ 84,707	$ 84,927	$ 88,480	
128	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ 4,600	
129	FCCF				
130	Energy Efficiency Revenues	$ 12,885	$ 12,908	$ 22,000	
131	Miscellaneous	$ 3,420	$ 3,420	$ 3,420	
132	**Total Revenue Credits**	**$ 187,664**	**$ 176,746**	**$ 206,727**	
133					
134	**Augmentation Costs**				
135	**IOU Reduction of Risk Discount (includes interest)**	$ 23,024	$ 23,024		
136	(Net augmentation power costs are not subject to True-Up)				
137	**Forecasted Gross Augmentation Costs**				
138	Residual augmentation cost	$ 49,005			
139	Other augmentation cost	$ 97,062	$ 95,001	$ 161,122	
140	Minus revenues	$ 67,993	$ 42,972	$ 73,667	
141	**Net Cost of Augmentation**	**$ 101,098**	**$ 75,053**	**$ 87,455**	
142					
143					
144	**Minimum Required Net Revenue calculation**				
145	Principal Payment of Fed Debt for Power	$ 202,331	$ 172,483	$ 103,065	
146	Irrigation assistance	$ -	$ 2,950	$ 7,279	
147	Depreciation	$ 118,058	$ 121,829	$ 118,832	
148	Amortization	$ 71,658	$ 76,332	$ 69,748	
149	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ (45,937)	
150	Bond Premium Amortization	$ 613	$ 613	$ 185	
151	Principal Payment of Fed Debt exceeds non cash expenses	$ 57,939	$ 22,596	$ (32,484)	
152	Minimum Required Net Revenues	**$ 57,939**	**$ 22,596**	**$ -**	
153					**3-Year Total Rev Reqt**
154	Annual Slice Revenue Requirement (Amounts for each FY)	**$ 2,240,934**	**$ 2,198,018**	**$ 2,302,550**	**$ 6,741,502**
155					
156	SLICE TRUE-UP ADJUSTMENT CALCULATION				
157	FY 2007-2009 Average Slice Revenue Requirement determined in WP-07 Rate Case	**$ 2,252,465**			
158	FY 2007-2009 Average Slice Revenue Requirement determined in WP-07 Supplemental Rate Cas	**$ 2,247,167**			
159	TRUE UP AMOUNT (Diff. between actual Slice Rev Reqt and forecast average Slice Rev Reqt)			**$ 55,383**	
160	AMOUNT BILLED (22.6278 percent)			**$ 12,532**	
161	Slice Implementation Expenses (not incl. in base rate)			**$ 2,486**	
162	TRUE UP ADJUSTMENT			**$ 15,018**	
163					
164					
165	**SLICE RATE CALCULATION ($)**				
166	**Monthly Slice Revenue Requirement (3-Year total divided by 36 months)**				**$ 187,263,943**
167	**One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Rev. Req't. divided by 100)**				**$ 1,872,639**
168					
169	**ANNUAL BASE SLICE REVENUES**				**$ 508,484,525**
170	**Annual Slice Implementation Expenses**				**$ 2,486,000**
171	**TOTAL ANNUAL SLICE REVENUES**				**$ 510,970,525**

ERRATA

Errata to
WP-07 Supplemental Power Rate Case
FY 2009 Wholesale Power Rate Development Study
WP-07-FS-BPA-13

Chapter 3

Page 36 line 12 – replace section 3.4 with Tables 3.6.1 and 3.8.2.
Page 37 line 25 – replace WP-07-E-BPA-05A with WP-07-E-BPA-05.
Page 44 line 10 – replace RAM2007 with RAM2009
Page 46 line 26 – replace billion with million
Page 52 line 24 – replace Table 2.6.2 with Table 2.6.1
Page 141-

Rows 14-15, Change word "Decomissioning" to "Decommissioning."

Table row 55, "Efficiencies Program (omit TMS expenses)" for FY 2009 forecast, remove value "$5,423" and enter "$ - ."

Table row 56, "Information Technology" for FY 2009 forecast, remove value "$ - " and enter "$5,423."

Page 142-
Table row 159, remove value "$55,383."

Table row 160, remove value "$12,532."

Table row 161, remove value "$2,486."

Table row 162, remove value $15,018."