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

2007 Wholesale Power Rate Case Initial Proposal

WHOLESALE POWER RATE DEVELOPMENT STUDY

November 2005

WP-07-E-BPA-05

WHOLESALE POWER RATE DEVELOPMENT STUDY
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APPENDIXES

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COMMONLY USED ACRONYMS

AANR	Audited Accumulated Net Revenues
AC	Alternating Current
AER	Actual Energy Regulation
Affiliated Tribes	Affiliated Tribes of Northwest Indians
AFDUC	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
ANRT	Accumulated Net Revenue Threshold
AOP	Assured Operating Plan
APS	Ancillary Products and Services (rate)
ASC	Average System Cost
Avista	Avista Corporation, Water Power Division
BASC	BPA Average System Cost
BiOp	Biological Opinion
BOR	Bureau of Reclamation
BPA	Bonneville Power Administration
BP EIS	Business Plan Environmental Impact Statement
Btu	British thermal unit
C&R Discount	Conservation and Renewables Discount
C&R	Cost and Revenue
CalPX	California Power Exchange
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CBP	Columbia Basin Project
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAC	Columbia Falls Aluminum Company
Cfs	Cubic feet per second
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
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
CRITFC	Columbia River Inter-Tribal Fish Commission
CSP	Customer System Peak
CSPE	Columbia Storage Power Exchange
CT	Combustion Turbine
CWA	Clear Water Act

CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DJ	Dow Jones
DMP	Data Management Procedures
DO	Debt Optimization
DOE	Department of Energy
DROD	Draft Record of Decision
DSIs	Direct Service Industrial Customers
DSR	Debt Service Reassignment
ECC	Energy Content Curve
EFB	Excess Federal Power
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
Energy Northwest, Inc.	Formerly Washington Public Power Supply System (Nuclear)
Energy Services	Energy Services, Inc.
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FBPF	Forward Flat-Block Price Forecast
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
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)
FSEA	Federal Secondary Energy Analysis
F&WCA	Fish and Wildlife Coordination Act
FY	Fiscal Year (Oct-Sep)
GAAP	Generally Accepted Accounting Principles
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	Generator Step-Up Transformers
GTA	General Transfer Agreement
GWh	Gigawatthour

HELM	Hourly Electric Load Model
HLFG	High Load Factor Group
HLH	Heavy Load Hour
HOSS	Hourly Operating and Scheduling Simulator
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IOU REP Settlement benefits	Investor-Owned Utilities Residential Exchange Program Settlement benefits
IOUs	Investor-Owned Utilities of the Pacific Northwest
IP	Industrial Firm Power (rate)
IP TAC	Industrial Firm Power Targeted Adjustment Charge
IPC	Idaho Power Company
ISC	Investment Service Coverage
ISO	Independent System Operator
KAF	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
K/I	Kilowatt-hour/Investment Ratio for Low Density Discount
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
LRSCP	Lower Snake River Compensation Plan
m/kWh	Mills per kilowatt-hour
MAC	Market Access Coalition Group
MAF	Million Acre Feet
MC	Marginal Cost
MCA	Marginal Cost Analysis
MCS	Model Conservation Standards
M/M	Meters/Miles-of-Line Ratio for Low Density Discount
Mid-C	Mid-Columbia
MIMA	Market Index Monthly Adjustment
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)
MW	Megawatt (1 million watts)
MWh	Megawatt-hour
NCD	Non-coincidental Demand

NEC	Northwest Energy Coalition
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NEW	Northwestern Energy
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
NPV	Net Present Value
NR	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NT	Network Transmission
NTP	Network Integration Transmission (rate)
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
NWPPC C&R	Northwest Power Planning Council Cost and Revenues Analysis
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
OURCA	Oregon Utility Resource Coordination Association
ORC	Operating Reserves Credit
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PATH	Plan for Analyzing and Testing Hypotheses
PBL	Power Business Line
PDP	Proportional Draft Points
PDR	Power Discharge Requirement
PF	Priority Firm Power (rate)
PFBC	Pressurized Fluidized Bed Combustion
PFR	Power Function Review
PGE	Portland General Electric Company
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PNCA	Pacific Northwest Coordination Agreement

PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection
POM	Point of Metering
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Project Act	Bonneville Project Act
PSA	Power Sales Agreement
PSC	Power Sales Contract
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point
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
RFA	Revenue Forecast Application
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
RTF	Regional Technical Forum
RTO	Regional Transmission Operator
SCCT	Single-Cycle Combustion Turbine
SCRA	Supplemental Contingency Reserve Adjustment
Shoshone-Bannock	Shoshone-Bannock Tribes
SOS	Save Our Wild Salmon
Slice	Slice of the System product
STREAM	Short-Term Risk Evaluation and Analysis Model
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TBL	Transmission Business Line
tcf	Trillion Cubic Feet
TCH	Transmission Contract Holder
TDG	Total Dissolved Gas
TPP	Treasury Payment Probability

Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
UCUT	Upper Columbia United Tribes
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
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
WY	Watt-Year
Yakama	Confederated Tribes and Bands of the Yakama Nation

1. OVERVIEW OF THE STUDY

1.1 Overview of the Studies. The Wholesale Power Rate Development Study (WPRDS) calculates BPA proposed rates based on information either developed in the WPRDS or supplied by the other studies that comprise the BPA rate proposal. All of these studies, and accompanying documentation, provide the details of computations and assumptions. In general, information about loads and resources is provided by the Load Resource Study (LRS), WP-07-E-BPA-01, and the LRS Documentation, WP-07-E-BPA-01A. Revenue requirements information, as well as the Planned Net Revenues for Risk (PNNR), is provided in the Revenue Requirement Study, WP-07-E-BPA-02, and its accompanying Revenue Requirement Study Documentation, WP-07-E-BPA-02A and WP-07-E-BPA-02B. The Market Price Forecast Study (MPFS), WP-07-E-BPA-03, and the MPFS Documentation, WP-07-E-BPA-03A, provide the WPRDS with information regarding seasonal and diurnal differentiation of energy rates, as well information regarding monthly market prices for Demand Rates. In addition, this study provides information for the pricing of unbundled power products. The Risk Analysis Study, WP-07-E-BPA-04, and the Risk Analysis Study Documentation, WP-07-E-BPA-04A, provide short-term balancing purchases as well as secondary energy sales and revenue. The Section 7(b)(2) Rate Test Study, WP-07-E-BPA-06, and the Section 7(b)(2) Rate Test Study Documentation, WP-07-E-BPA-06A, implement Section 7(b)(2) of the Northwest Power Act to ensure that BPA preference customers' firm power rates applied to their general requirements are no higher than rates calculated using specific assumptions in the Northwest Power Act.

1.2 Organization

The WPRDS is divided into six sections including this introduction. These sections are: Rate Design Changes; Cost Allocation and Rate Design Implementation; Inter-Business Line Revenues and Expenses; Revenue and Purchased Power Expense Forecast; and Rate Schedule

Descriptions. In addition, the WPRDS includes three appendices. These are the 7(c)(2) Industrial Margin Study; the Value of DSI Supplemental Contingency Reserves; the Nature of the Slice of the System (Slice Product), and the Market Power Analysis. Details supporting calculations and data are in the WPRDS Documentation, WP-07-E-BPA-05A and WP-07-E-BPA-05B.

This rate proposal includes minor changes in the calculation and design of wholesale power rates. In doing so, BPA has also revised its rate design to reflect cost causation and market conditions more accurately and to continue to provide price signals that result in more efficient use of the FBS resources.

The primary changes in BPA Power rate design are as follows:

(1) Use of market forecasts to develop the monthly Demand Rates to send more accurate price signals to customers. This is discussed further in Section 2.2.1.1 below.

(2) The primary cost drivers of the Load Variance Rate are based on the customer's right to place load growth on BPA and load variations due to weather. BPA has analyzed the costs of meeting both load growth and load variations during the first 44 months of this rate period in developing this rate for this proposal and applied that information in developing the Load Variance Rate for this proposal. Further discussion of this change is in Section 2.2.4 below.

(3) BPA is including six Federal holidays in the light-load-hour (LLH) period for consistency with the market for short-term electricity sales. These are January 1, Memorial Day, July 4, Labor Day, Thanksgiving, and December 25. If any of these fall on a Sunday, then the following Monday is deemed to be a LLH period.

(4) BPA is proposing to provide an Operating Reserves credit to those customers who purchase Operating Reserves from TBL that are provided by PBL. Previously a credit for Operating Reserve revenue had been provided to all firm power requirements customers.

2. RATE DESIGN

This chapter is divided into 17 sections. The first section discusses energy rates. The second discusses the derivation of the Demand Rates and the Demand Adjuster, the derivation of the Load Variance Rate, and the rate for Load Factoring Service. The third section discusses the proposed Operating Reserves Credit. The fourth discusses the Unauthorized Increase and Excess Factoring Charges. The fifth section discusses the Firm Power Products and Services (FPS-07) rates for capacity, firm power, and for capacity without energy. The sixth section discusses the flexible PF and NR rates. The seventh section discusses the PF Exchange rates. The eighth discusses Irrigation Mitigation Rates. The ninth discusses the availability and changes to the Low Density Discount. The tenth section discusses the Conservation and Renewable program, the Conservation and Renewable Credit, and the Renewable Option. The eleventh section discusses the Green energy Premium. The twelfth section describes the Targeted Adjustment Clause. The thirteenth section deals with the General Transfer Agreements (GTA) delivery Charge. The fourteenth section is devoted to the Slice product. The fifteenth section discusses the proposed Cost Recovery Adjustment Clause. The sixteenth section describes LB CRAC true-ups that will occur during the next rate period. And the last section describes the Average System Cost (ASC) forecasts for IOUs and public utilities. There is some discontinuity in the numbering of tables in this section of the WPRDS and the associated documentation because these sections were prepared by many people and were among the last items to be compiled.

2.1 Monthly and Diurnal Differentiation of Energy Rates

In establishing rates for FY 2007-2009, BPA uses the same basic approach used in the previous Wholesale Power rate case. More specifically, BPA shaped energy rates according to market-based marginal costs established by BPA market forecast for the FY 2007-2009 period. BPA power revenue requirements reflect the costs associated with the market for at least three reasons: (1) rates that follow market prices are more efficient since revenue from foregone sales is closer to the revenue received from energy sales; (2) monthly rates represent a continuation of the current rate design and would result in no significant cost to implement; and (3) due to physical constraints imposed on the system to save anadromous fish less flexibility remains for operating BPA system to meet firm power loads.

BPA is setting diurnal monthly energy rates for the FY 2007-2009 rate period. The MPFS, WP-07-E-BPA-03, shows substantial monthly and diurnal variation in predicted energy prices for this period. Therefore, it is not appropriate for BPA to have less than 12 seasons for Heavy Load Hour (HLH) and Light Load Hour (LLH) energy rates.

BPA established HLH and LLH energy rates for FY 2007-2009 using the following five steps:

(1) BPA estimated its market energy prices for HLH and LLH for each month using marginal costs for the FY 2007-2009 rate period, S*ee,* MPFS, WP-07-E-BPA-03;

(2) Monthly Demand Rates were calculated using the results from the MPFS, WP-07-E-BPA-03, *See* Section 2.2.1.2 below. The monthly Demand Rates are lower than the 2002 Demand Rates because the Demand Rate is based on deviations above the average HLH price for each three month period rather than the deviations above the average annual energy price for each 12 month period as was used in the 2002 rates. After

incorporating this change there was no need to cap the demand rate as had been done in the prior rate filing. The monthly demand rates are shaped in proportion to the average monthly HLH energy prices. The development of the Demand Rate is discussed in Bolden, *et al*., WP-07-E-BPA-13.

(3) The Load Variance Rate was calculated using historical deviations of full and partial requirements HLH and LLH energy loads and the difference of those from the forecasted values for those loads, projected market prices and the initial proposal PF rates for the three-year rate period to determine the expected cost of load forecast error. The projected year-over-year load growth for full and partial requirements customers, and the difference between projected market prices and initial proposal rates was used to calculate the cost of load growth. *See* Section 2.2.4 below, and Bolden, *et al*., WP-07-E-BPA-13;

(4) Estimated FY 2007-2009 demand and load variance revenues were subtracted from BPA FY 2007-2009 revenue requirement along with other revenue credits; and

(5) Monthly HLH and LLH energy prices from the MPFS, WP-07-E-BPA-03, were reduced proportionately until estimated revenues from energy rates equaled the balance of BPA power revenue requirements, to ensure BPA did not over-collect revenues.

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 issues with BPA Core Subscription Products. This section will discuss Demand, Load Factoring, and Load Variance.

2.2.1 Core Subscription Products Principles BPA designed its 2002 rates with a new approach that encompassed equitable comparability among purchasers, a common table of rates, and the concept of an effective rate. BPA then incorporated these elements into BPA Core Subscription Product design. This design approach primarily concerned two rate design items known as the Demand Charge and the Load Variance Charge.

BPA Core Subscription Products are 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 Charges for Core Subscription Products 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 service BPA calls "factoring" in which energy is distributed among hours to match a load shape; and (3) readiness to meet actual load under peaking conditions. When combined with energy charges, a Demand Charge has the effect of increasing the purchaser's average payment per kWh of product, sometimes referred to as the effective rate. If the power delivery is not flat, the resulting demand charge plus energy charge makes the effective rate increase compared to a flat power purchase. To help maintain and assure equitable comparability, the same demand dollar rate ($/kW-month) will be applied to appropriate demand billing factors for different products such as Full Service, Partial Service, and Block products.

2.2.1.2 Development of Power Rates Demand Charge BPA is proposing two energy rates for each month. However, the MPFS (WP-07-E-BPA-03) demonstrates there is a different market value for power in each hour. To account for the hourly differential, BPA is proposing a Demand Rate applied in conjunction with the energy rate. The effect of this combination results in a shaped load paying a higher effective rate than a flat load. This is consistent with generally accepted ratemaking principles of cost causation and sending appropriate price signals.

2.2.1.2.1 Methodology The methodology to derive a Demand Charge uses the AURORA market price forecast. The AURORA model simulates serving all loads and recovering all costs through hourly energy prices. The positive differences between HLH energy prices and quarterly average HLH energy prices are the values used to determine the Demand Rate. AURORA models hourly energy prices, but these hourly energy prices alone are not appropriate to recover all demand costs. The reason average HLH energy prices alone are not appropriate is that the shaped loads would pay only the average price, which is less than the cost of serving shaped loads during HLH periods. The additional costs caused by the shaped loads are those costs above the average peak period price. The Demand Rate reflects these higher hourly peak period costs. For AURORA prices
S*ee,* the "Hourly Data" Table in MPFS Documentation, WP-07-E-BPA-03A, Section 2.

The Demand Rate is developed from AURORA market prices as follows, S*ee,* Table 4.2 in WPRDS Documentation, WP-07-E-BPA-05B.

(1) The difference between forecast peak period hourly prices above the quarterly average HLH price are computed for the three-year period, and reflects the value of firming, factoring, and peaking costs.

(2) The hourly amounts are summed by month for the three-year period.

(3) This total value is converted to $/kW for the three years by dividing by 1,000.

(4) This value is converted to an average $/kW-month by dividing by the 36 months.

(5) This average $/kW-month value is shaped using AURORA average monthly HLH prices to derive a monthly market-based Demand Rate.

2.2.1.2.2 Results The three-year annual average Demand Rate is $1.06/kW-month. Monthly rates are as stated in the rate schedules. *See,* Wholesale Power Rate Schedules (WPRS) and General Rate Schedule Provisions (GRSPs), WP-07-E-BPA-07.

2.2.2 Factoring Service in Core Subscription Products The term "factoring" is a term of general usage 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 (MWh) among hours during certain periods to follow load. The term "periods" refers to the HLH and LLH periods of rate seasons, *e.g.,* calendar months and years. 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 only be checked in the billing process for customers with declared resources with hourly variability, which are dispatchable, and who purchase the Actual Partial (Complex) product. This is because 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 an hour-to-hour basis is there a possibility of receiving Factoring Service amounts which are less than or greater than the entitlement amount. BPA posted product descriptions, in the BPA Power Product Catalog, provide further details on the factoring benchmark calculation. Factoring Service that is within the benchmark results in no excess service penalty charges. The entitled amount of Factoring Service will be paid for at 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 Business Line (TBL) or a negotiated backup service.

2.2.2.1 Factoring Service as a Staple-On Product and the Appropriate Billing Demand
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 by the Demand Rate applied to an 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 rate filing for the rates that applied to customers purchasing partial service under 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.

The Demand Adjuster was developed to resolve this problem by adjusting billing demand megawatts (MW) 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 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 (six tenths).

2.2.4 Load Variance Rate In the context of Core Subscription Products, Load Variance is defined as the variability from forecast 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 the customer's actions to annex new load, retail access, or by service to New Large Single Loads (NLSL). Such loads will receive Load Variance coverage once the loads are served by BPA under the applicable firm power rate. BPA offers to stand ready to serve this 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 than for Block products where the amounts to be paid for are fixed in advance.

The Load Variance Rate is set at 0.53 mills/kWh and will be charged against the customer's TRL. For a discussion of the basis for the calculation of the Load Variance Rate, *See,* Section 2.2.4.1.

The Load Variance billing factor is the customer's TRL. Because of the Subscription product component called factoring, the Load Variance Charge is associated solely with the service of standing ready to meet variable monthly cumulative energy amounts.

2.2.4.1 Development of Power Rates Load Variance Rate

2.2.4.1.1 Methodology The methodology for the Load Variance Rate estimates the amount of incremental (or marginal) cost BPA incurs when providing Load Variance service. The cost is standing ready to serve an unknown quantity at an unknown cost, but at a fixed price. When loads are above or below the forecast, BPA could purchase or sell in the market at an unknown price. The changes in actual HLH and LLH energy loads from their forecast value during the previous 36 months were calculated. The average monthly load forecast error was about 2.8%. This load forecast error was used to estimate a portion of the cost of the Load Variance product. *See*, WPRDS Documentation, WP-07-E-BPA-05B, Chapter 2.2.

Load growth is the increase in projected monthly HLH and LLH energy sales in FY 2008 and FY 2009 over the HLH and LLH energy sales during each of the same months in FY 2007. These amounts are multiplied by the difference between the projected market average monthly peak and off-peak prices and the corresponding initial proposal HLH and LLH PF energy rate to determine the cost of serving load growth, the other component of Load Variance cost. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Chapter 2.2.

The combined costs of load forecast error and load growth are summed over the thirty-six month period to obtain the total cost of providing the Load Variance product. This cost was converted to the Load Variance rate by dividing the total projected cost by the sum of the projected Load Variance billing quantities. *See,* WPRDS Documentation, WP-07-E-BPA-05B, Table 4.3.

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 is 0.53 mill/kWh. *See,* Table titled "Load Variance Rate. *See,* WPRDS Documentation, WP-07-E-BPA-05B, Table 4.3. *See,* Bolden, *et al*., WP-07-E-BPA-13. The Load Variance Rate is published in the WPRS, WP-07-E-BPA-07, and applies to the PF-07 and NR-07 rate schedules.

2.3 Development of Power Rates Operating Reserve Credit (ORC) PBL does not know with certainty which customers will choose to purchase Operating Reserves from the TBL. This uncertainty led to an under-recovery and a rate inequity in the last rate period. To avoid this in the future, PBL is proposing an ORC with will provide customers with a credit on their power bill if they choose to purchase Operating Reserves from the TBL. This rate design will better match the source of the dollars that create the revenue credit with the actual revenues received by a customer through its power bill and will ensure that PBL does not collect more than the total revenue requirement.

2.3.1 Methodology for non-Slice Customers The methodology to derive an ORC was based on the expected revenue from selling generation inputs to TBL for the provision of Operating Reserves. *See,* Section 4.1.3 below. The total expected revenue was based on an amount of generation inputs that PBL now expects to sell to customers who we anticipate will purchase from TBL due to annual election or a requirement in their transmission contract with TBL. The total expected revenue from Operating Reserves provided by the PBL over the rate period is $108.4 million. The forecasted load of customer purchased Operating Reserves is 135,120,000 MWh. Those total revenues are divided by the forecast loads for customers purchasing Operating reserve from TBL, which yields a rate of $0.89/MWh. *See,* WPRDS Documentation, WP-07-E-BPA-05B, Table 4.7.

2.3.2 Overview of the Slice Methodology The general method of determining the Slice and Slice/Block ORC was to estimate the total cost of providing sufficient generation inputs to TBL to provide Operating Reserves for its entire Control Area Obligation. That total cost was allocated to each group of PF customers including Slice and Slice/Block and the costs were calculated in such a way that the rate for Operating Reserves was the same as that paid by full and partial requirements customers.

2.3.3 Detailed Slice Methodology To determine the ORC credit for the Slice product, the value of all Operating Reserves is multiplied by the Slice percentage. The value of all Operating Reserves provided by PBL is the sum of Spinning and non-Spinning Operating Reserves and is reported on line 12 of Table 4.7. Operating Reserves are valued at the same per unit charge (*i.e.* $6.96/kW-mo) developed for the expected sale of generation inputs to the TBL. *See,* Table 4.7 in WPRDS Documentation, WP-07-E-BPA-05B.

2.4 Unauthorized Increase Charges and Excess Factoring Charges

This power rate 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 indexes in the penalty charge derivations also ensures an appropriate deterrent against customers placing demand, energy, and factoring burdens on 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 WPRDS Documentation, WP-07-E-BPA-05B.

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 proposed 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,* GRSPs, WP-07-E-BPA-07, 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 California ISO 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 for any purchaser taking demand in excess of its contractual entitlement. The minimum charge will be set at three times the monthly Demand Charge from the applicable power rate schedule. The effective charge may be set at a level that exceeds the minimum based on the sum of the hourly California ISO 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 tested against 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 GRSPs, WP-07-E-BPA-07, Section II.Q; and examples from a recent 12-month period can be found in WPRDS Documentation, WP-07-E-BPA-05B, Table 4.6.1, and Table 4.6.2.

2.4.2 Excess Factoring Charges This rate 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 kWh, 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: (1) the highest HLH price, and less (2) the lowest (same day) HLH price will be tested against the 5 mills/kWh minimum to determine the applicable charge. A corresponding test against the 5 mills/kWh minimum will be applied for LLH 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 amounts greater than the upper boundary; or (2) the sum of the 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 mill/kWh. This minimum will be tested against charges derived from the DJ Mid-C Index prices for firm power and the California ISO Supplemental Energy indexes for the month. For HLH Excess Within-Month Factoring Energy, the effective charge will be the greater of: (1) 5 mill/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 mill/kWh minimum price will be done to determine the effective Excess Within-Month Factoring for LLH.

The Excess Within-Month Factoring quantities are reduced by any Unauthorized Increase in 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 GRSPs, WP-07-E-BPA-07, Section II; and examples of these charges from a recent 12-month period can be found in WPRDS Documentation, WP-07-E-BPA-05B, Table 4.6.3 and Table 4.6.4.

2.5 Firm Power Products and Services (FPS-07)

2.5.1 FPS Posted Rates

Posted energy rates were determined using the average of monthly HLH/LLH from the AURORA hourly price forecast. Customers taking energy under these rates are also subject to the posted demand rate. These prices are subject to negotiation.

The posted FPS Demand Rate equals $83.55 per year based on the computed rate for supplemental control area reserves, and the monthly rate is proportional to the monthly HLH energy rate as a percentage of the summed HLH energy rates. *See,* WP-07-E-BPA-5B, Table 4.8.

2.5.2 Firm Capacity without Energy

The annual cost of FPS Capacity without Energy Rate is equal to the annual cost of adding capacity as determined in WP-07-E-BPA-05B, Table 4.8. The monthly FPS Capacity without Energy rate was shaped by determining the using the forecasted monthly average HLH prices for the rate period, dividing by the sum of the forecasted monthly average HLH prices, and multiplying that percentage by the annual cost of additional capacity. The forecasted monthly average HLH prices were developed using the AURORA model which is documented in the MPFS Documentation, WP-07-E-BPA-03A, Section 2. The forecasted hourly energy prices were grouped into HLH and LLH periods. The six NERC holidays were included with the other LLHs. All of Sunday as well as the first six and last two hours of Monday through Saturday were the basic LLH period. If January 1, July 4, or December 25 fell on a Sunday then Monday was deemed to be a holiday. Memorial Day, Labor Day, and Thanksgiving were also included with the LLH period. The monthly average prices are documented in WPRDS Documentation, WP-07-E-BPA-05B, Table 4.8.

In addition to the FPS Monthly Capacity without Energy Rate, customers purchasing this product would be required to return energy taken and to pay an energy differential based on market differences at the time the energy is returned. An estimate of returned energy rates is shown in WP-07-E-BPA-05B, Table 4.8. This is the forecast average HLH rate for the month less the forecast average LLH rate for the month.

2.6 Flexible PF and NR

The Flexible PF and NR rate option is offered at BPA's discretion to PF and NR Preference purchasers who make a contractual commitment 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 a purchaser under this option. The actual charges and billing factors will be mutually agreed to by BPA and the purchaser subject to satisfying the following condition:

- Equivalent Net Present Value Revenues: Forecasted 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.

2.7 PF Exchange Rates

The PF Exchange Rate applies to the traditional implementation of the REP. This rate is compared with the exchanging utility's ASC and the difference is multiplied by the utility's eligible retail load to determine monetary benefits paid to the utility by BPA. This rate also applies to BPA actual power sales to exchanging utilities under traditional "in-lieu" transactions.

The PF Exchange Rate Demand Rate is the same as the PF Preference rate Demand Rate. The PF Exchange energy rates are seasonally differentiated in a manner similar to the PF Preference energy rates. The PF Exchange Rate includes a rate for Load Variance. A charge for Load Regulation or its successors, as established by BPA TBL, and the Network Integration Transmission (NT) rate or its successor for transmission service, also as established by TBL, are forecasted and included in the initial proposed PF Exchange Rate. The actual Load Regulation rate and NT rate, as established by the TBL, will be used in determining the PF Exchange Rate during the rate period.

2.8 Irrigation Rate Mitigation

This proposal continues to provide irrigation customers with rate mitigation for 153 aMW of irrigation loads consistent with their contract. These sales are identified as Irrigation Mitigation sales and are made at contractually specified rates that increase by the amount of the PF rate increase.

2.9 Low Density Discount (LDD)

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 LDD principles, eligibility criteria, and discount calculation table appear in the GRSPs of the WPRS, WP-07-E-BPA-07, Section II.K.

In the past the LDD was 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 K/I ratio). The other formula calculated the ratio of the number of the utility's consumers to the number of pole miles of distribution lines (the C/M ratio). These ratios are determined based on 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 included any areas outside the PNW, BPA compiled data submitted by the purchaser separately on the purchaser's system in the PNW and on the purchaser's entire electric utility system inside and outside the PNW. BPA applied 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 was 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 0 to 5 percent, in one-half percent increments. 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 7 percent.

BPA is proposing to modify the 2002 LDD methodology used during FY 2002-2006 to improve consistency of submitted data, to ensure equity among customers, and to simplify administration. As in 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 FY, 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 estimated cost of the LDD is $24 million per year for the FY 2007-2009 rate period. The proposed changes to the LDD for the FY 2007-2009 rate period are:

(1) Changes to the "Retail Rate to PF Rate" Eligibility Criterion. The first sentence in Section 2. c. of the Eligibility Criteria has been changed to: "the Purchaser's average retail rate for the reporting year must exceed BPA's average Priority Firm power rate for the most closely corresponding fiscal year by at least 25 percent."

This change is necessary to account for BPA's separation of power and transmission rates in 1996, and ensures that customers with very low retail rates do not qualify for the LDD.

(2) Changes to the Average Cost of BPA Power Purchases. The definition of the denominator in the retail rate threshold has been changed from "the Purchaser's average cost of BPA power purchases" to "BPA's average Priority Firm power rate." This change simplifies administration of the LDD program by avoiding the need to calculate Purchaser-specific average costs of BPA power purchases.

(3) Definition of "Average Retail Rate." The term "average retail rate" is now explicitly defined as follows:

> "Average retail rate is equal to total retail electricity sales (revenue) divided by total retail electricity sales (kWh), both as reported on the LDD data requirements reporting form submitted by the customer."

This change is necessary to avoid potential disputes and clearly establish the basis for calculating the average retail rate.

(4) Changing "Consumers" in the C/M Ratio to "Meters". The term "consumers" in the C/M ratio has been changed to "meters." The ratio now becomes the M/M ratio.

This change provides a more accurate reflection of density, provides a uniform basis for calculating the ratio, and ensures greater equity among customers.

(5) Application of the LDD to Slice. BPA will estimate the Slice Product Purchaser's LDD based on the "Critical Inventory Amount" and "Selected Slice Percentage" rather than the "Critical Slice Amount," and later true-up the LDD based on the Purchaser's "Requirements Slice Output" as defined in the Slice Contract. Since BPA does not currently collect the data necessary to determine the Requirements Slice Output, implementing this change will require Slice Product Purchasers eligible for the LDD to provide BPA the data necessary to calculate and verify the Requirements Slice Output each October for the previous fiscal year so the Individual Credit or Individual Charge can be calculated along with the annual Slice True-up.

This change more accurately reflects the intent of the LDD, and ensures that the LDD only applies to net requirements purchases.

2.10 Conservation and Renewable 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 Renewable Discount (C&R Discount) and is intended to help implement the program goals set forth in BPA's policy direction 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 and accompanying Administrator's Record of Decision (Near-Term Policy/ROD). *See,* WPRDS Documentation, WP-07-E-BPA-05B, Section 4.10.

BPA's Near-Term Policy expresses five principles to guide the development of BPA's conservation acquisition programs in the post-2006 period. 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,* WPRDS Documentation, WP-07-E-BPA-05B, Chapter 4.10, "Final Post-2006 Conservation Program Structure."

The structure and program design for the CRC was developed through a collaborative work group process. As part of the near-term regional dialogue, BPA relied on collaborative workgroup members to assist in developing a fully defined conservation proposal. The collaborative process started in September 2004 and resulted in a 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 2007-2009. During this collaboration BPA signaled its desire to act in a facilitator role for regional renewable development and has included specific facilitation monies in FY 2007 and FY 2008 rates for this purpose. BPA's existing long-term renewable resource acquisition costs will be included in FBS system costs along with the forecasted costs associated with proposed facilitation activities.

The amount of revenues from Green Energy Premiums (GEP) and Green Tags depends on actual market conditions and costs. Actual facilitation expenditures will vary somewhat from the budgeted amounts because the facilitation budget partly depends upon GEP and Green Tag (Renewable Energy Certificate) revenues, which will be added to the fixed renewable facilitation budget at the end of each fiscal year. BPA will review renewable program costs and revenues annually. BPA will use that comparison to manage total renewable facilitation expenditures to a net of $21 million per year to support its renewable facilitation activities. This $21 million serves as a policy benchmark target for funding the renewable program components and was discussed in the power function review. *See,* Near-Term ROD at 67-77. BPA's existing long term renewable resource acquisition costs are included in FBS system costs. *Id*.

2.10.1 Conservation Rate Credit (CRC)

To encourage its customers to undertake conservation projects and develop renewable resources, BPA is making available the CRC to the PF-07, NR-07, and IP-07 rates. The CRC is also available to eligible purchasers of the Slice product and is included in the calculation of the benefits provided in the IOU REP Settlement benefits. While the IP-07 rate is subject to the CRC, BPA forecasts no power sales to DSI customers under the IP rate for the rate period, *See,* LRS, WP-07-E-BPA-01, Chapter 2.2.4, therefore, BPA has forecasted zero DSI participation in the CRC.

To calculate the CRC cost, 0.5 mill/kWh was applied to forecasted requirements loads served by the eligible rate schedules and the Slice product. The 0.5 mill/kWh rate discount level was established for the FY 2002-2006 rate period as part of the C&R Discount. *See,* Esvelt, *et al*., WP-02-E-BPA-33, at 6. Customers eligible to receive the CRC will not be required to reduce (i.e., require a decrement) the amount of firm requirements power purchased from BPA. *See,* WPRDS Documentation, WP-07-E-BPA-05B, Section 4.10, "Final Post-2006 Conservation Program Structure." CRC costs are included in the COSA as part of conservation program costs.

The CRC will be reflected as a line item reduction on the customers' monthly BPA power bills. Individual monthly reductions will be 0.5 mill/kWh multiplied by one-twelfth of the customer's forecasted annual purchases from BPA under its Subscription contract. For Slice customers, the forecasted annual purchase will be based on their contractual percentage share of 7070 aMW. For non- Slice customers their forecasted annual purchases will be based on each customer's forecast net requirements. IOU REP settlement benefits will be included as power equivalents in this calculation. Each customer's expected series of 36 equal monthly line item reductions will be calculated prior to the FY 2007-2009 rate period. REP settlement benefits will be included as power equivalents in this calculation. Based on compliance with conservation and renewables implementation manual guidelines, BPA reserves the right to adjust the specific amount of CRC received by each customer as necessary through out the rate period. *See,* GRSPs, WP-07-E-BPA-07 at 73.

BPA assumes the CRC will generate no net revenue during the rate period. BPA is assuming all eligible customers will participate in the CRC. Participation in the CRC program occurs when customers accept the credit and pay their monthly bills at the reduced rate. 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 Manual, as may be 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 adjustment removed from their monthly bills and will pay the unadjusted bill total. *See, Id.* at 75.

Only CRC expenditures incremental to spending customers would have otherwise made pursuant to direction of a public utility customer's governing board, or state law, or regulation, are eligible for the CRC. 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 in the amount of the CRC received and the customer's actual total qualifying expenditures. *Id.*

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. 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 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. While all measures must be cost-effective, acceptable measures do not need to be on an approved measure list to be eligible for the CRC. A renewables 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 each year in 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. *See,* GRSPs, WP-07-E-BPA-07 at 75.

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 2007-2009 rate period, which ever 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 discounts for the rate period, customers will be required to reimburse BPA the difference. *Id.*

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 2007-2009 rate period. Utility customers that sign bilateral contracts with BPA (Con/Aug) obligating the customer to deliver actual energy savings will be required to reduce their Firm net requirements loads for the FY 2007-2009 rate period. *See,* WPRDS Documentation, WP-07-E-BPA-05B, Section 4.10, "Final Post-2006 Conservation Program Structure."

BPA reserves the right to inspect and/or audit customers to verify claims of units or completed units and the ability to monitor or review utility records, verified energy savings method and results, or otherwise and 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 Renewables Option of the Conservation Rate Credit

A renewable energy 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 renewables program will reimburse the conservation program annually for renewable claims up to the $6 million dollar cap. A utility customer participating in the renewables 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 FY 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 exempted 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-07, and NR-07 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/MWh 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/EPP costs 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; (3) endorsement fees for specific EPP resources.

BPA currently forecasts GEP revenue will average $1.4 million annually over the rate period. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Table 3.6.2. BPA has included a matching $1.4 million annual renewable facilitation cost in the renewable program budget for FY 2007-2009. This is a result of BPA's policy decision to reinvest GEP revenues in additional renewable activities.

2.11.1 Conservation Costs

The Northwest Power Act directs BPA to encourage development of conservation and energy efficiency within the Pacific Northwest. As a resource, 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,* WPRDS Documentation, WP-07-E-BPA-05B, Appendix C, "Final Post-2006 Conservation Program Structure*.* These savings are expected to be acquired at an average cost of $1.54 million/aMW for a total of $75 million. *Id.*

The "conservation" line item, as seen in the COSA 06 tables, S*ee,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, includes: (1) debt service for BPA previous resource acquisition activities; (2) BPA continuing contributions to the region's market transformation efforts; (3) costs associated with BPA 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 the COSA 09 tables, S*ee,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, reflects payments provided by other BPA organizations and Federal agencies for the energy efficiency services delivered.

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 third party and 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,* WPRDS Documentation, Table 3.6.2, WP-07-E-BPA-05B. Existing renewable projects that BPA purchases energy from include: 37% of Foote Creek I Wind Project, 100% of Foote Creek II Wind Project, 100% of Foote Creek IV Wind Project, 100% of Klondike I Wind Project, 30% of Stateline I Wind project, and 100% of Condon Wind Project. These projects are expected to produce 51 aMW annually. *See,* LRS, WP-07-E-BPA-01A, Table 2.3.1. Purchase costs for the output from existing and contracted public purpose renewable resources projects are documented in the WPRDS as part of the FBS system costs. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Tables COSA 06 for FY 2007 through FY 2009.

In addition, BPA has contracted to purchase energy output from the Fourmile Hill Geothermal Project. This purchase project is still in an exploratory drilling phase and is not yet a proven resource. For purposes of this study costs related to such purchase are forecasted to commence in FY 2009, or year 3 of the rate period. *See,* LRS, WP-07-E-BPA-01A, Table A23.

2.12 Targeted Adjustment Charge (TAC)

BPA proposes to establish rates based on expected Requirements load per the load forecast which was finalized June 30, 2005, for the WP-07 Initial Proposal. Under the PF-07 and NR-07 rate schedules (with exception for the PF Exchange Rate), all customer requests for additional Requirements service that occur after June 30, 2005, will be subject to a Targeted Adjustment Charge (TAC). The TAC will apply for the duration of the rate period. For the next rate period (FY 2010-2011) where such load can be incorporated into the load forecast in the Initial Rate Proposal, it will qualify for posted PF rates. 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.

The TAC will apply to subsequent requests made by a customer under a Subscription contract for Requirements service for such customer's load(s) 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. The TAC will also apply to purchases under the NR-07 rate.

BPA may exempt newly acquired load from the TAC and apply the PF-07 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 service has been previously served by the customer's 5(b)(1)(A) or 5(b)(1)(B) resources because it would increase BPA's total load obligation.

BPA may exempt any load from the TAC and offer the applicable posted rate if the 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 BPA power or financial benefits through Subscription, the public agency customer will receive, by assignment through BPA, the right to the IOU's financial benefits applicable to the annexed load. BPA will deliver an amount of firm power to the annexing public agency customer at the PF-07 rate equal to the amount of financial 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 until FY 2010, whichever occurs first. If a new public requests service, the TAC will apply until FY 2010.

For the WP-07 Power Rate Case, BPA has forecast that no loads will be served under the 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 power revenue requirement for the FY 2007-2009 rate period. If the cost of power to serve these loads is above BPA embedded costs, BPA financial reserves may be impacted. 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 shall apply to the incremental power acquired by BPA which 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 rate case, with updates to the LRS Documentation, WP-07-E-BPA-01A, 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 power to serve the incremental load is available, such power shall be sold at the PF-07 rate, or the NR-07 rate. In the event power is not available and BPA must acquire additional power to meet the load, such additional power shall be sold at the PF-07 rate, or the NR-07 rate, plus an adjustment charge reflecting the difference between the PF-07 rate, or NR-07 rate, and BPA cost to supply this power.

BPA will calculate the total cost of the additional power for a specific customer request based on BPA 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 MWh of the incremental load to obtain a levelized $/MWh 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-07 rate or the NR-07 rate. The TAC will be applied in addition to the monthly HLH and LLH energy rates, demand charge, and load variance charge for the applicable month or months as specified in the applicable rate schedules.

BPA will calculate the cost for the TAC at the time a customer requests power under this schedule. The TAC will be finalized prior to signing of the final contract or before initial delivery.

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: (1) a certifiable renewable resource eligible for the CRC; or (2) contract purchases of certified renewable resource power eligible for the CRC, for a period less than the term of the customer's BPA Requirements firm power contract, then the customer may request Requirements firm power service during the FY 2007 to 2009 rate period for such load at the PF-07 rate, to the end of the specified contract period, without being subject to the TAC .

2.13 GTA Delivery Charge The GTA Delivery Charge is a Power Business Line (PBL) 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 PBL power customers that take delivery at voltages under 34.5 kV, when PBL 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 been established in the TBL rate case. In the 2002 and 2004 Transmission Rate Settlement Agreements, the GTA Delivery Charge mirrored the TBL's Utility Delivery rate. As part of the 2006 Transmission Rate Case Settlement Agreement, the GTA Delivery Charge was set to $1.119 per kilowatt month for the period October 1, 2005 to September 30, 2007, which mirrors TBL's Utility Delivery rate for that period. The monthly Billing Factor for the GTA Delivery Charge for this period 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. *See,* 2006 Final Transmission Proposal, Administrator's Record of Decision, Appendix B: 2006 Transmission & Ancillary Service Rate Schedules, TR-06-A-01, Section II, H.2.

For the PBL rate period covering October 1, 2007, through September 30, 2009, PBL is proposing that the GTA Delivery Charge continue to mirror TBL's Utility Delivery rate under the posted Delivery Charge schedule in the approved Transmission & Ancillary Service Rate Schedules. PBL's rate for the GTA Delivery Charge for the October 1, 2007, to September 30, 2009, period will be adjusted as changes are made to TBL's posted Delivery Charge for Utility Delivery for that period. The approximate revenue associated with the GTA Delivery Charge is forecast to be $2.3 million per year.

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

2.14.1 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 amount of Slice product available to a customer is based upon a Slice customer's annual net firm requirements load, compared to an annual average firm energy load carrying capability of 7,070 average megawatts (aMW), and is shaped to BPA's generation output from the FCRPS. The annual average firm energy load carrying capability of 7,070 aMW was calculated in the WP-02 rate case for the FCRPS, as adjusted by System Obligations. BPA's sale of the Slice product required a commitment by the Slice customer of 10 years, from FY 2002 through FY 2011.

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

2.14.2 Slice Revenue Requirement

Each Slice customer pays a percentage of BPA's costs, rather than a set price per MW and MWh. The Slice customer's obligation to pay is equal to the percentage of the FCRPS generation output that the Slice customer elected to purchase in its 10-year Subscription contract. The costs paid by Slice customers are referred to collectively as the Slice Revenue Requirement. The Slice Revenue Requirement is comprised of all of the line items in BPA's generation revenue requirement, with certain limited exceptions (S*ee,* WPRDS*,* WP-07-E-BPA-05, Chapter 2.14, Table 1, Slice Product Costing and True-Up Table, for a detailed list of the line items and forecasted dollar amounts in the Slice Revenue Requirement).

2.14.3 Inclusion and Treatment of Expenses and Revenue Credits

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

The following paragraphs clarify the rate treatment of particular items in the Slice Revenue Requirement and Actual Slice Revenue Requirement. The Slice Revenue Requirement includes all the expenses and revenue credits that are the basis for calculating the Slice rate for the FY 2007-2009 period. The expenses and revenue credits included in the Slice Revenue Requirement are forecasts for the FY 2007-2009 period. The Actual Slice Revenue Requirement includes the same expense and revenue credit categories as the Slice Revenue Requirement, but is comprised of the final audited actual expenditures and revenues as reflected on BPA's PBL financial statements. The Actual Slice Revenue Requirement for a given FY is used as the basis for the calculation of the annual Slice True-Up Adjustment Charge for that FY (*See,* Section 2.15.4, Slice True-Up for a more detailed description of the Slice True-Up process).

2.14.3.1 Augmentation Expenses

In the WP-02 rate case, BPA took steps to supplement the capability of the FBS to meet the total load placed on BPA. Augmentation was defined as the power purchases that were needed, on a planning basis, to meet all load service requests made under BPA's Subscription contracts. Augmentation has been referred to as the "inventory solution" for purposes of the Slice product. For the WP-07 rate case, the term "augmentation" will be used, instead of "inventory solution." Conceptually, augmentation purchases are considered to be separate and distinct from "balancing purchases." "Balancing purchases" refer to those purchases used to replace reduced hydro system flexibility due to increased operating constraints and to those purchases needed to serve BPA's load on an hourly and monthly basis. Slice customers do not pay for BPA's "balancing purchases," as the Slice customers face the risk of reduced hydro system flexibility directly and have the obligation to serve their own loads on an hourly and monthly basis.

The WP-02 rate case established that the Slice customers would be required to pay their proportionate share of the net cost of all augmentation expenses. The "net cost" of augmentation refers to the costs associated with the purchase of the augmentation power less the associated revenues from the sale of such augmentation power. Slice customers would not receive any power associated with augmentation purchases.

BPA forecasts that there will be augmentation expenses during the FY 2007-2009 rate period. BPA will have three types of augmentation expenses in the FY 2007-2009 rate period. The three types of expenses include: (1) "residual" augmentation expenses; (2) "deferred" augmentation expenses; and 3) other augmentation expenses.

The first type of expenses, "residual" augmentation expenses, contains the expenses associated with augmentation purchases that carried over from the FY 2002-2006 rate period into the FY 2007-2009 rate period. When BPA purchased power on the market to meet its load obligations for the FY 2002-2006 period, some of the purchases extended to the end of the 2006 calendar year rather than ending at the close of the rate period (September 30, 2006). The MWs associated with the "residual" augmentation purchases are not needed to meet BPA's forecasted load for FY 2007. Under the provisions of the LB CRAC, the Slice customers would not have paid for this augmentation expense because this power is not needed to meet BPA's load. The net cost of this "residual" augmentation power is assumed to be zero. Therefore, the Slice product will not be assessed any related charges (*See,* WPRDS, WP-07-E-BPA-05. Chapter 2.14, Table 1, Slice Product Costing and True-Up Table, line 128).

The second type of augmentation expenses is "deferred" augmentation. This category contains those augmentation expenses incurred during the FY 2002-2006 rate period, but the payment of which is deferred to the FY 2007-2009 rate period and beyond. The "deferred" augmentation expenses are 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 (Puget) and PacifiCorp. Puget and PacifiCorp agreed to forgo collection of the one half of the Reduction of Risk Discount ($100 million) and deferred collection of the balance ($100 million) until the FY 2007-2011 period. With interest payments, this results in a $115 million of deferred augmentation expenses for FY 2007-2011, and will be recovered through PF rates in amounts of approximately $23 million per year.

The third type of expenses, "other" augmentation expenses, includes the augmentation purchase expense that BPA is forecasting it will make to meet its load obligation during FY 2008-2009. BPA is forecasting a need to augment the system during FY 2008 and FY 2009 for 38 aMW and 92 aMW, respectively. *See*, Hirsch*, et al.,* WP-07-E-BPA-09. Slice customers will pay their proportionate share of the "net cost" of these augmentation purchases. For the net cost calculation, BPA assumes that it will purchase augmentation power in FY 2008 at 56 mills per kWh and at 54 mills per kWh in FY 2009. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Table 3.6.2. and Wagner, *et al.,* WP-07-E-BPA-12. The revenues associated with the sale of augmentation power are estimated, based on the projected PF rate for power and multiplied by the amount of power that will be sold (38 aMW and 92 aMW, respectively for FY 2008, FY 2009). The projected PF rate is 31 mills per kWh. BPA subtracts the expected revenues from the forecasted purchase expense to calculate the net cost of the augmentation purchases for FY 2008-2009. The net cost of augmentation for FY 2008-2009 will not be subject to the Slice True-Up process. However, if there are relevant updates to the assumptions used in calculating the net cost of augmentation between BPA's Initial Proposal and Final Proposal, the net cost of augmentation numbers will reflect those changes.

2.14.3.2 Conservation Augmentation (ConAug)

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

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

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

BPA independently decided to capitalize the costs of actual ConAug acquisitions. As a result there is annual amortization expense associated with ConAug investments from the FY 2002-2006 rate period that carry over into the FY 2007-2009 period. 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 2007-2009 rate period, because Slice customers paid a forecast of ConAug costs as if they were incurred as annual expenses. Therefore, the amortization will be excluded from the Slice Revenue Requirement and the Actual Slice Revenue Requirement.

2.14.3.3 IOU Residential Exchange Program (REP) Settlement Benefits

Slice customers will pay their proportionate share of any IOU REP Settlement benefits payments to PNW IOUs under the IOU REP Settlement Agreements during the FY 2007-2009 rate period. There are two aspects to the payments to the IOUs: (1) the balance of the FY 2003 $55 million payment deferral for all IOUs not repaid as of September 30, 2006, which results in an annual payment to the IOUs of $3.7 million over the 5-year period beginning October 2006; and (2) IOU REP Settlement Benefits to all six IOUs (Avista Corporation, Idaho Power Company, NorthWestern Energy Division of NorthWestern Corporation, Portland General Electric Company, PacifiCorp, and Puget Sound Energy) applied to the FY 2007-2011 period, specified under their contracts or contract amendments entitled, "Agreement Regarding Payment of Residential Exchange Program Settlement Benefits during FY 2007-2011."

The "balance of the $55 million payment deferral for all IOUs not repaid as of September 30, 2006" was accounted for as an expense in FY 2003, and the Slice customers paid their proportionate share of this expense through the True-Up Adjustment in that year. Therefore the balance still owed on September 30, 2006, will not be included as an expense in the Slice Revenue Requirement for purposes of calculating the Slice rate, nor will it be accounted for as an expense in the Actual Slice Revenue Requirement for the FY 2007-2009 period for purposes of the annual Slice True-Up.

The interest associated with the $55 million currently is being accounted for as an expense in the Actual Slice Revenue Requirement for calculation of the True-Up Adjustment Charge during the FY 2002-2006 rate period. The interest is included in the FY 2007-2009 Slice Revenue Requirement for purposes of calculating the Slice rate (S*ee,* Table 1 WP-07-E-BPA-05, Chapter 2.14, Slice Product Costing and True-Up Table, line 87). The interest also will be accounted for as an expense in the Actual Slice Revenue Requirement for calculation of the True-Up Adjustment Charge in the FY 2007-2009 period. Currently, the interest is forecast to be approximately $1 million annually.

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

The amount of the IOU REP Settlement benefits payments to all six IOUs is not fixed but rather will change each year depending on the difference between an independent market price forecast and lowest-cost PF rate (including any CRAC or DDC). In addition to the new methodology, the FY 2007–2011 contracts or contract amendments provide both a cap and a floor for benefit levels. The IOU REP Settlement benefits to be paid by BPA during any fiscal year has a floor of $100 million and a cap set at $300 million. BPA currently is forecasting the benefit amount to be at or near the cap during the upcoming rate period.

2.14.3.4 Cost of the Residential Exchange for Public Utilities

Whatever the costs of the Residential Exchange Program (REP) for public utilities are, if any, Slice customers will pay their proportionate share of those costs. For the WP-07 Initial Proposal, BPA is not forecasting any REP costs for public utilities. However, if the forecast for REP costs for public utilities changes in the Final Proposal, such costs will be included in the Slice Revenue Requirement for the WP-07 Final Rate Proposal. Actual costs of the REP for public utilities in any year will be included in the Actual Slice Revenue Requirement for that year, for purposes of calculating the Slice True-Up.

2.14.3.5 Bad Debt Expense

The Slice Revenue Requirement contains a line item labeled, “Other Accounts.” This line item contains the amounts associated with “Bad Debt Expense” and “Other Income, Expenses, and Adjustments,” both of which are line items in PBL’s Statement of Revenues and Expenses. While no amounts are forecasted for the FY 2007-2009 period, the compilation of the Actual

Slice Revenue Requirement will contain whatever is accounted for in these accounts. Through the annual Slice True-Up, Slice customers will pay their proportionate share of these expenses.

While no bad debt expense amounts are forecasted for the FY 2007-2009 period, the compilation of the Actual Slice Revenue Requirement will contain whatever is accounted for in these accounts. BPA managers evaluate the probability of collection of receivables in any given year and determine what amounts would be recognized as an expense to be included in the Actual Slice Revenue Requirement for purposes of calculating the Slice True-Up in that year. These expenses are accounted for under Generally Accepted Accounting Principles (GAAP) in BPA's financial statements.

Because Slice customers paid their proportionate share of the bad debt expenses recognized by BPA in previous fiscal years (FY 2002-2006), Slice customers will be credited for any incoming dollars associated with the reversal of previous write-offs of bad debt expenses.

2.14.3.6 DSI Costs

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 and 17 aMW to Port Townsend Paper Corporation for the FY 2007-2011 period. *See,* Gustafson*, et al.,* WP-07-E-BPA-17. These costs will be 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.

2.14.3.7 Fish Program Costs

Slice customers will pay their proportionate share of BPA's direct program costs for fish and wildlife. 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 deviate from the forecasts contained in the Slice Revenue Requirement, Slice customers will pay their proportionate share of any increase or decrease in direct program costs through their annual True-Up. Slice customers would be affected in real-time for any changes in indirect program costs for fish and wildlife, through changes in their Slice power deliveries.

Slice customers will not be subject to the NFB Adjustment. Slice customers will pay their proportionate share of any changes in direct program costs through their annual True-Up and, as mentioned previously, any indirect program cost changes (e.g., changed operations or increases in spill and flow) will be experienced through changes in Slice power deliveries.

2.14.3.8 Slice Implementation Expenses

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

Projections of Slice Implementation Expenses are not included in the Slice Revenue Requirement, and therefore, are not included in the Slice rate. Slice Implementation Expenses in any given FY will be accounted for after the audited year-end Actual Slice Revenue Requirement for that FY is available. Slice Implementation Expenses will be charged to Slice customers through the annual Slice True-Up for that FY.

2.14.3.9 Debt Optimization Program

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

The financial effects from the refinancing and the related additional amortization of Federal debt are accounted for in the Actual Slice Revenue Requirement. The revenues generated from these refinancing will not be allocated.

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 rate of general application through the implementation of the Cost Recovery Adjustment Charge mechanisms. Inclusion of the Debt Optimization program transactions in the annual True-Up Adjustment Charge is recognition of the Slice customers' share of these obligations.

2.14.3.10 Operating Reserves Revenue Credit

Operating Reserves revenue credits are associated with payments from BPA's TBL to PBL for PBL-supplied generation inputs for Operating Reserves. TBL receives revenue from transmission customers who purchase Operating Reserves from TBL to meet their entire reserve obligation to the BPA control area. A portion of the revenues collected from these customers is paid back to PBL for PBL-supplied generation inputs. *See,* Bermejo*, et al.,* WP-07-E-BPA-20.

The revenues associated with TBL's payments to PBL for Operating Reserves amount is projected to be approximately $35 million per year in the FY 2007-2009 period. This revenue is forecasted from PBL's estimated annual average reserve obligation amount multiplied by the generation input rate for Operating Reserves demand across the rate period. In the WP-02 rate case, this amount was included in the Slice Revenue Requirement, as part of the Ancillary and Reserves Services revenue credit (S*ee,* Table 1 below, Slice Product Costing and True-Up Table, line 107). In the WP-07 Initial Proposal, BPA proposes to remove the component of the Ancillary and Reserves Services revenue credit associated with TBL payments to PBL for Operating Reserves. See Section 2.3 of this study for further explanation. Instead a direct credit will be provided to only those Slice purchasers that purchase Operating Reserves from TBL.

2.14.4 Slice Rate

The Slice Revenue Requirement is the basis for calculating the base Slice rate. To calculate the Slice rate, the total dollar amounts for each FY of the Slice Revenue Requirement 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,* WPRDS, WP-07-E-BPA-05, Chapter 2.14 Table 1, Slice Product Costing and True-Up Table, line 140). For the WP-07 Initial Proposal, the estimate of the monthly Slice rate is $1,892,726 per percent Slice product purchased. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.3, Table Slice Cost 01.

2.14.5 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 Slice Revenue Requirement for the individual FY and actual expenses and credits in the Actual Slice Revenue Requirement for the FY. The Actual Slice Revenue Requirement for the applicable FY is the sum of the final audited expenditures and revenues as reflected on BPA's PBL financial statements, corresponding to those PBL 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 Slice Revenue Requirement is called the Slice True-Up Amount. A positive or negative result from the 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 mitigates BPA's financial risks in the event that any of these conditions put adverse financial pressure on BPA. The Slice customers' payments through their base Slice rate and the annual True-Up Adjustment Charge mitigates the risk associated with the variability of BPA's expenses and revenue credits (for those expenses included in the Slice Revenue Requirement). The risks associated with the variability of generation output and with the uncertainty of market prices for purchasing or selling power are assumed directly by the Slice customers.

Table 1

Slice Product Costing and True-Up Table

	PBL Costs ($000)			Audited Actual Data	2007 forecast	2008 forecast	2009 forecast
1	PBL Costs ($000)						
2	GENERATION COSTS						
3	Federal Base System						
4	Hydro						
5	Upstream benefits (PNCA headwater benefits)		11		1,714	1,714	1,714
6	Corps of Engineers O&M		6		161,519	165,742	170,407
7	Corps Depreciation		25				
8	U.S. Fish & Wildlife O&M		8		18,600	19,500	20,400
9	U.S. Fish & Wildlife Depreciation		25				
10	Bureau of Reclamation O&M		6		71,654	74,760	77,766
11	Bureau Depreciation		25				
12	Colville Settlement		6		16,968	17,354	17,749
13	Spokane Settlement				0	0	0
14	Packwood Dam		6				
15	**Subtotal**				**270,455**	**279,070**	**288,036**
16	Fish and Wildlife						
17	Expense, including Environmental Requirements		30		143,500	143,500	143,500
18	Amortization		26				
19	**Subtotal**				**143,500**	**143,500**	**143,500**
20	Trojan						
21	Decommissioning		22		9,300	5,200	2,200
22	Debt Service		21		8,605	7,888	0
23	**Subtotal**				**17,905**	**13,088**	**2,200**
24	WNP #1						
25	O&M WNP 1 & 3		22		50	52	54
26	Debt Service, includes Reassignment		21		160,673	168,644	166,011
27	**Subtotal**				**160,723**	**168,696**	**166,065**
28	WNP #2						
29	O&M/Capital Requirements		6		256,300	206,300	238,800
30	Debt Service		21		254,455	237,858	259,072
31	**Subtotal**				**510,755**	**444,158**	**497,872**
32	WNP #3						
33							
34	LIBOR interest rate swap				0	0	0
35	Debt Service		21		160,848	161,088	153,997
36	**Total**				**1,264,186**	**1,209,600**	**1,251,670**
37							
38	New Resources						
39	Idaho Falls		6				
40	Idaho Falls Debt Service		21				
41	Cowlitz+ Emerald		6				
42	Cowlitz+ Emerald Debt Service		21		11,619	13,247	13,739
43	Firm Purchased Power						
44	Competitive Acquisitions		6				
45	Columbia Hills (CARES)						
46	Wheeling Power Purchase		6				
47	Other Acquisitions						
48	**Total**				**11,619**	**13,247**	**13,739**
49							
50	Legacy Conservation						
51	Conservation expense	#	29		29,488	28,650	28,387
52	Generation Billing Credits		6				
53	Conservation Financing		21		5,203	5,198	5,196
54	Conservation Amortization		26				
55	**Total**				**34,691**	**33,848**	**33,583**
56	Energy Services Business		7		12,885	12,908	12,933
57	Other Generation Costs						
58	BPA Programs						
59	PBL Efficiencies		6		1,553	1,584	1,616
60	telemetering				200	200	200
61	Power Marketing		10		27,421	28,136	28,942
62	Other Power Marketing expenses						
63	PBL Salary Costs Mrktg, transm acqu, risk analys				-5,360	-5,360	-5,360
64	Power Scheduling		9		14,115	14,570	15,040
65	Inventory Solution Hedging Activities						
66	Generation Oversight		6		6,049	6,165	6,286
67	Administrative & Support Services	12	14		50,615	52,127	52,144
68	CSRS				10,550	9,000	15,375
69	Power Planning Council		30		9,085	9,276	9,467
70	Miscellaneous Depreciation		24		111,269	112,762	114,773
71	Miscellaneous Amortization				55,262	59,936	64,866

Table 1, continued

Slice Product Costing and True-Up Table

72	Geothermal Demonstration	29				
73	Renewables	29	26,214	32,143	55,356	
74	Long-term Generating Projects		24,666	25,054	25,452	
75	Contingency Resources					
76	Net Interest Expense	31	179,504	188,406	196,646	
77	Between Business Line Expense					
78	Other Projects					
79	Other Accounts, including Bad Debt expense	27	59,000	59,000	59,000	
80	WNP #3 Plant					
81	**Total Other Generation Costs**		**583,028**	**605,906**	**652,737**	
82	**Minimum Required Net Revenues**		**34,105**	**42,876**	**27,599**	
83	**COSA Table Subtotal**		**1,927,630**	**1,905,477**	**1,979,328**	
84						
85	**PBL Costs ($000)**					
86	Net Residential Exchange Costs					
87	Subscription Settlement Costs		301,000	301,000	301,000	
88	CEA Transmission Costs		24,806	25,550	26,991	
89	Ancillary and Reserve Service Costs	10	8,462	8,462	8,462	
90	PBL PF Trans. Pass-Through Costs					
91	PNCA & NTS Transmission Costs	9	1,775	1,825	1,875	
92	Other System Obligations Net Costs					
93	General Transfer Agreement Costs	10	47,000	47,000	48,000	
94	**REVENUE REQUIREMENT CHECK**		**2,310,673**	**2,289,314**	**2,365,656**	
95						
96	Individual Charges & Credits					
97	PF Conservation and Renewables Credit Costs		42,000	42,000	42,000	
98	IP Conservation and Renewables Credit Costs					
99	RL Conservation and Renewables Credit Costs					
100	LDD		18,000	18,000	18,000	
101	Irrigation Rate Mitigation Costs		12,000	12,000	12,000	
102	**Non-COSA Table Subtotal**		72,000	72,000	72,000	
103						
104	**Total PBL Revenue Requirement**		**2,382,673**	**2,361,314**	**2,437,656**	
105						
106	**Revenue Credits ($000)**					
107	Ancillary and Reserve Service Revs. Total		49,453	48,803	48,948	
108	PBL PF Trans. Pass-Through Revs.					
109	Canadian Entitlement Credit					
110						
111	COE & USBR Project Revenues		3,600	3,600	3,600	
112	4(h)(10)(c)		79,117	75,844	72,457	
113	Colville Credit		4,600	4,600	4,600	
114	FCCF					
115	Sup/Ent Cap; Irr. Pump		5,321	5,321	5,321	
116	Energy Efficiency Revenues		12,800	12,800	12,800	
117	Property Trnfrs & Misc.		3,420	3,420	3,420	
118						
119	**Total Revenue Credits**		**158,311**	**154,388**	**151,146**	
120						
121	**Power Revenues Needed**		**2,224,363**	**2,206,926**	**2,286,511**	
122						
123	**Augmentation Costs**					
124	**IOU Reduction of Risk Discount (includes interest)**		23,000	23,000	23,000	
125	**Costs in this box are not subject to True-Up**					
126	**Forecasted Gross Augmentation Costs**		49,063	18,626	43,721	
127	(Gross power purchase cost)					
128	Minus revenues		49,063	10,348	24,984	
129	**Net Cost of Augmentation**		**23,000**	**31,278**	**41,737**	
130						
131	**SLICE TRUE-UP ADJUSTMENT CALCULATION**					**3-Year Total Slice Rev. Reqt.**
132	**Annual Slice Revenue Requirement (Amounts for each FY)**		**2,247,363**	**2,238,204**	**2,328,248**	**$ 6,813,815**
133	**TRUE UP AMOUNT (Diff. between actuals and forecast)**					
134	**AMOUNT BILLED (22.6278 percent)**					
135	Slice Implementation Expenses (not incl. in base rate)		**2,300**	**2,300**	**2,300**	
136	**TRUE UP ADJUSTMENT**					
137						
138						
139	**SLICE RATE CALCULATION ($)**					
140	**Monthly Slice Revenue Requirement (3-Year total divided by 36 months)**					**$ 189,272,634.64**
141	**One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Revenue Requirement divided by 100)**					**$ 1,892,726.35**
142						
143	**ANNUAL BASE SLICE REVENUES**					**$ 513,938,798.66**
144	**Annual Slice Implementation Expenses**					**$ 2,300,000.00**
145	**TOTAL ANNUAL SLICE REVENUES**					**$ 516,238,798.66**
146						

2.15 Cost Recovery Adjustment Clause

2.15.1 Cost Recovery Adjustment Clause

The proposed Cost Recovery Adjustment Clause (CRAC) adjusts posted wholesale power rates upward if actual accumulated modified net revenues (AMNR) attributable to the generation function fall below the thresholds shown in Table A.

The CRAC applies to LLH and HLH energy sales under these firm power rate schedules:

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

The CRAC also applies to the calculations of:

- the 2200 aMW of monetary benefits provided to IOUs under IOU REP Settlement Agreement benefits; and

the benefits provided to DSI customers under the FY 2005 DSI Service ROD.

The CRAC does not apply to:

- sales under the Slice Rate; or
- power sales under Pre-Subscription contracts to the extent prohibited by such contracts.

The CRAC may affect rates as frequently as each year of the three-year rate period. The adjustment would be applied to power deliveries beginning in October following the fiscal year in which the threshold was passed, including FY 2006. Any such increase in any of the three fiscal years would remain in effect through September of that fiscal year. The level of planned rate increase to be collected through the CRAC is limited to the lower of the annual Maximum

Planned Recovery Amount in Table 2 below, or the amount by which the AMNR is below the threshold.

Table 2
CRAC Trigger Thresholds and Annual Caps

AMNR Calculated at end of Fiscal Year	CRAC Applied to Fiscal Year	CRAC Threshold (AMNR)	Approx. Threshold as Measured in PBL Reserves	Maximum CRAC Recovery Amount (Cap)*
2006	2007	-$193	$470	$300
2007	2008	-$36	$500	$300
2008	2009	-$45	$500	$300

* The Maximum CRAC Recovery Amount (Cap) may be modified to account for adjustments made to the Cap by the NFB Adjustment (if triggered) calculated at the end of each FYs 2006, 2007, and 2008.

2.15.2 National Marine Fishery Service/Federal Columbia Rivers Power System Biological Opinion Adjustment (NFB Adjustment)

The NFB adjustment results in an upward adjustment to the CRAC Maximum Recovery Amount (cap) for any year in the rate period if additional fish and wildlife costs arise from a specified set of circumstances. The NFB Adjustment calculation will result in an increase in the annual cap defined in Table 2 for the fiscal year following the year the NFB Adjustment was triggered. The NFB Adjustment is potentially applicable to each fiscal year of the rate. The NFB Adjustment will only address changes in financial impacts due to the anadromous fish portion of Fish and Wildlife cost categories, and only when those impacts result from changes in FCRPS Endangered Species Act (ESA) compliance as required by a court order (including court-approved agreements), an agreement related to litigation, a new NMFS FCRPS BiOp, or Recovery Plans under the ESA. Financial impacts include foregone revenue, power purchases, direct program expense, fish credits, COE and Reclamation Operations and Maintenance, and capital repayment. Financial impacts will be calculated net of estimated 4(h)(10)(C) credits. *See,* WP-07-E-BPA-04 for additional information on the NFB Adjustment Calculation

2.16 LB CRAC True-ups

BPA implemented a Load Based Cost Recovery Adjustment Clause (LB CRAC) for the FY 2002-2006 rate period. Procedures adopted as part of the GRSPs for that rate period set up a periodic detailed true-up and billing adjustment procedure that required review of actual billing and load data for the rate period. The final true up could not occur until after the conclusion of the FY 2002-2006 rate period. BPA will append the appropriate procedures to the FY 2007-2009 GRSPs. BPA will continue to implement only procedures necessary to complete the process as originally outlined. Specifically, LB CRAC 9 true-up bill adjustments will be continued for October, November and December of 2006 according to the LB CRAC workshop results established in June 2006. In addition, BPA will hold a LB CRAC workshop in December 2006 to establish the true-up billing adjustments for the LB CRAC 10 period. This policy applies only to those portions of the LB CRAC policy required to complete the true-up of LB CRAC 9 and LB CRAC 10 periods. LB CRAC methodologies will not be applied to any loads served after October 1, 2006.

2.17 Average System Cost Forecasts for the IOUs and Public Utilities

BPA forecasted Average System Costs (ASCs) and exchange loads for regional IOUs and selected public utilities. BPA is following, with a few noted exceptions, the 1984 Average System Cost Methodology (1984 ASCM). The IOUs are: Avista Utilities, Idaho Power, Northwestern Energy, PacifiCorp, Portland General Electric (PGE), and Puget Sound Energy.

BPA identified six public utilities that could potentially participate in the REP during the rate period. For purposes of this proceeding, BPA will refer to five of these public agencies as Utility

No. 1 through Utility No. 5 in order to safeguard these utilities' confidential information. The sixth utility, Clark Public Utilities, recently signed a Residential Purchase and Sale Agreement (RPSA) and submitted an ASC filing with BPA, thereby making public any potentially confidential information. After evaluating these utilities in detail, they were all considered candidates to have relatively high ASCs because they own thermal resources or are exposed to market volatility, or both.

BPA followed a two-step process to forecast ASCs. First, a base ASC for each utility was calculated by populating the ASC Cookbook Model with historical data. *See,* WPRDS Documentation, WP-07-E-BPA-05B, Table 4.12.1. Second, the base ASCs were forecasted using the ASC Forecast Model. *See,* WPRDS Documentation, WP-07-E-BPA-05B, Table 4.12.2. The ASC Forecast Model and process is described below.

PNGC utilities were not reviewed in detail, mainly because nine Pacific Northwest Generating Company (PNGC) utilities signed Residential Exchange termination agreements that extend though FY 2011. In addition, the PNGC utilities have a long-term power sales contract under which they sell their share of the Boardman coal plant to Turlock Irrigation District. In past ASC filings, the cost of Boardman was the primary cause for the PNGC utilities' high ASCs. Absent specific information regarding the Turlock contract, BPA assumed that the revenue from the power sale to Turlock would equal the cost of the PNGC utilities' annual share of the Boardman power plant.

2.17.1 Base ASC Calculations

BPA developed base ASCs using the most recently published financial and operating information for each utility. For the IOUs, BPA used the 2004 FERC Form 1s. Because public utilities are not required to file a FERC Form 1, BPA used the latest published annual report for each public utility. At the time the ASCs were being calculated, the only available annual reports were for either 2003 or 2004. Normally under a Residential Purchase and Sales Agreement (RPSA) utilities would provide the data for the ASC calculation directly. In the absence of the agreement BPA used available information.

Financial data from the IOU FERC Form 1s were entered into the Cookbook Model. BPA used a direct analysis method to review and functionalize costs relating to deferred debits, regulatory assets, and regulatory liabilities. The Cookbook Model has the following sections that are used to calculate a utility's ASC: (1) exchangeable rate base, which includes regulatory assets, derivative accounts, and return on rate base calculations; (2) operating costs; (3) taxes; and (4) wholesale market revenues and other credits.

2.17.1.1 Exchangeable Rate Base

The rate base for an ASC calculation consists of net production and transmission assets. The rate base also includes exchangeable current and deferred assets, as well as deferred liabilities that are functionalized to production and transmission. The following rate base issues were reviewed, with emphasis placed on studying sub-accounts and financial notes.

2.17.1.1.1 Regulatory Assets

Regulatory assets are deferrals of costs, and are a subset of Deferred Debits (FERC Accounts 183 and 186). Such costs have been incurred by a utility but have either not been placed in rates or have not been fully amortized through rates. Such costs are often large, and relate to operation of the utility. Examples of such assets include deferred power costs and pension benefits.

In the past, such accounts were relatively small and therefore either functionalized to distribution or functionalized on a preset ratio that is detailed in the 1984 ASCM. In some cases the utility would note specific assets and assign a functionalization. Functionalization is a process to allocate costs to production, transmission, or distribution. BPA functionalized each sub-account based on a review of the name, a brief description of the account and any explanation included in the financial notes.

2.17.1.1.2 Derivative Accounts

Derivative accounts represent the present value of future financial instruments. For example, a derivative account might be a hedge against future gas or power prices. Derivatives are also used to hedge the risk of changes in interest rates. Utilities are required to book assets and liabilities related to derivatives on their balance sheets.

BPA functionalized derivative accounts to distribution and other. There are four main reasons for this functionalization are: (1) the financial documents reviewed did not indicate the type of hedge instrument(s) used; (2) there was no indication whether an account was one or several different future transactions; (3) there was no explanation of when the hedge transaction was to be exercised or of the duration of the transaction; and (4) there was no discussion regarding regulatory commission treatment of the assets.

2.17.1.1.3 Return on Rate Base Calculation

The first step in calculating the return on rate base is determining the cost of capital. The 1984 ASCM established that only the cost of debt is used to determine the cost of capital. For this study, BPA derived the cost of capital by dividing total interest expense by total long-term debt. The second step, return on rate base, was calculated by multiplying exchangeable rate base by the cost of capital percentage. Return on rate base is a direct cost that is included in the total exchange cost calculation.

2.17.1.2 Operating Costs

Operating costs include operation and maintenance costs associated with generating resources and transmission plants. BPA included all purchased power costs in operating costs, and functionalized wholesale market revenues to production as a credit. Depreciation and amortization costs were functionalized to the appropriate category and added to production costs. Administrative and General (A&G) costs were functionalized using the Production, Transmission, and Distribution (PTD) ratio. Absent labor studies that would have been provided with an ASC filing, BPA used the PTD ratio as a proxy to determine A&G functionalization.

2.17.1.3 Taxes

The 1984 ASCM requires all income-related taxes to be functionalized to distribution. In this study, BPA followed the ASCM in functionalizing taxes. Non-income taxes were functionalized either by set ratios or through direct analysis. For the public utilities, if there were no tax detail in the annual reports, BPA assumed taxes were in lieu of property taxes and functionalized such taxes using the PTD ratio. For the IOUs, BPA used tax data that were reported as "Taxes Paid During Year" in the FERC Form 1.

2.17.1.4 Wholesale Market Revenues and Other Credits

BPA functionalized most wholesale market revenues to production. BPA assumed a utility's resources were used first to meet its requirements load, and then to support its wholesale marketing activities. BPA assumed utilities would not always recover 100 percent of potential wholesale market revenues due to market conditions, so BPA reduced the annual wholesale market revenue credits by 20 percent.

BPA functionalized other revenue accounts and revenue credits using either the Cookbook Model preset ratios, or by direct analysis if there was sufficient information.

2.17.1.5 PacifiCorp Inter-Jurisdictional Cost Allocation

PacifiCorp provides a unique inter-jurisdictional issue relating to the calculation of its ASC. BPA first entered PacifiCorp's total utility cost data from the FERC Form 1 into the Cookbook Model. In order to allocate PacifiCorp's total system to the Pacific Northwest (PNW)states, BPA adjusted PacifiCorp's ASC based on the Inter-Jurisdictional Cost Allocation System developed jointly by the state commissions that regulate PacifiCorp. This system allocates PacifiCorp's total electric operations proportionately to each state in which it has load and regulated rates. BPA used PacifiCorp's "Oregon Jurisdiction, Results of Operations, March 2002" filing before the Oregon Public Utility Commission (OPUC). BPA transferred the PNW allocation factors to the corresponding accounts in the Cookbook Model. The total costs in each account were then multiplied by the PNW allocation factors to produce PacifiCorp PNW costs.

2.17.2 Net Exchange Costs

BPA calculated net exchange costs by adding the following costs and revenues that were functionalized to production and transmission: Net Exchange costs = Operating cost + Return on Rate base - Wholesale market revenues and other revenue credits

2.17.3 System and Residential Loads

System loads are a utility's total retail load (TRL). TRL is the total metered load a utility bills its customers. The 1984 ASCM requires that distribution losses be included in TRL; BPA added a loss factor of five percent to each utility's reported TRL. The distribution loss factor will vary with each utility, due to the age of the system and the population density factors. TRL including the distribution loss factor is the denominator in the ASC calculation.

To forecast residential loads, BPA first developed a residential factor for the ASC Forecast Model. The residential factor for each utility was calculated by dividing its residential load by its TRL. The residential factor was applied to growth in total retail load to determine residential load growth. BPA assumed the residential load factor for each utility remains constant over the study period.

2.17.4 Base ASCs

The base ASC for each utility is calculated in the final step of the Cookbook Model. This step divides the total exchange costs by the total retail load. In Table 3, the base ASCs, TRL, and exchange loads are shown for each utility reviewed in this study.

2.17.5 ASC Forecasts

ASC results from dividing Contract System Costs (total exchangeable costs) by Contract System Load (total retail load). BPA forecasted ASCs by forecasting the costs and loads embedded in base ASCS.

2.17.5.1 Cost Forecasts

BPA held base ASCs constant for the years between the base year (either 2003 or 2004 depending on data availability) and 2006. Because loads increased during this period, exchangeable costs were proportionately increased in order to maintain a constant ASC.
For the 2006-2013 study period, BPA used the ASC Forecast Model to forecast the utilities' load and resource balances (system resource requirements including losses, and resource position), sales for resale revenues, purchased power costs, non-fuel costs, and fuel costs. The ASC

Forecast Model used inflation escalators, gas price forecasts, and market price forecasts to escalate base ASC costs through year 2013.

2.17.5.2 Load Forecasts

Internal BPA load forecasts were used for the study period. Distribution losses were added to each utility's forecast. The percentage relationship of residential load to total retail load in the base ASCs was held constant for each utility over the study period.

Actual system and exchange loads are shown in Table 3, and forecasted system and exchange loads are shown in Table 4.

2.17.6 Developing Forecasted Purchased Power and Wholesale Sales

Forecasts of a utility's purchased power costs and wholesale sales revenue are a function of changes in the utility's TRL. The ASC Forecast Model balances any annual change in TRL by adding purchases or reducing wholesale sales. The model forecast future resource costs from each utility's base year resources, including any known resource additions or reductions.

2.17.7 IOU Exchange Cost Forecasts

BPA calculated IOU Exchange costs for 2006 as follows. The individual utility ASC Forecast Models are shown in WPRDS Documentation, WP-07-E-BPA-05B, Section 4.12.2.

Exchange Cost $_{2006}$ = NF Exchange Cost $_{2005}$ + ((Wholesale Revenue Credit$_{2005}$) * (1 + Inflation Deflator)) - Wholesale Revenue Credit$_{2006}$ + Cost of Load Growth + Fuel Cost

NF Exchange Cost $_{2005}$ is non-fuel costs for a utility. Wholesale Revenue Credit is the product of annual Wholesale Sales (MWh) and the annual Market Price Forecast. Cost of Load Growth is

Table 3

	Investor Owned Base ASCs	
	WP-07 Proceeding	WP-02 Proceeding
Avista		
ASC $ /Mwh	40.97	29.25
TRL Mw hours	8,795,447	
Residential load Mw hours	3,510,227	
Residential load Mwa	401	
Idaho Power		
ASC $ /Mwh	38.57	25.71
TRL Mw hours	13,901,568	
Residential load Mw hours	6,135,452	
Residential load Mwa	700	
Pacificorp		
ASC $ /Mwh	35.53	30.09
TRL Mw hours	22,561,484	
Residential load Mw hours	10,058,325	
Residential load Mwa	1,148	
Portland General		
ASC $ /Mwh	41.81	36.68
TRL Mw hours	18,652,345	
Residential load Mw hours	7,633,624	
Residential load Mwa	871	
Puget Sound Energy		
ASC $ /Mwh	40.05	39.01
TRL Mw hours	20,870,630	
Residential load Mw hours	10,508,203	
Residential load Mwa	1,200	
Northwester Energy PNWR		
ASC $ /Mwh	54.97	33.12
TRL Mw hours	6862352.7	
Residential load Mw hours	2,580,940.95	
Residential load Mwa	295	

Table 3 continued

	Public Utility's Base ASCs WP-07 Proceeding
Clark County PUD	
ASC $ /Mwh	48.12
TRL Mw hours	4,445,950
Residential load Mw hours	2,214,450
Residential load Mwa	253
Utility #1	
ASC $ /Mwh	45.38
TRL Mw hours	1,659,789
Residential load Mw hours	604,618
Residential load Mwa	69
Utility #2	
ASC $ /Mwh	46.63
TRL Mw hours	44
Residential load Mw hours	242,882
Residential load Mwa	28
Utility #3	
ASC $ /Mwh	50.88
TRL Mw hours	1,031,807
Residential load Mw hours	457,090
Residential load Mwa	52
Utility #4	
ASC $ /Mwh	48.94
TRL Mw hours	611,922
Residential load Mw hours	269,179
Residential load Mwa	31
Utility #5	
ASC $ /Mwh	46.95
TRL Mw hours	6,851,259
Residential load Mw hours	3,073,454
Residential load Mwa	351

the product of any annual increase in a utility's TRL (MWh) and the annual Market Price Forecast.

Annual Fuel Cost is calculated as follows:

$$\text{Fuel Cost}_{2006} - \text{Fuel Cost}_{2005}$$

$$\text{Fuel Cost}_{2006} = \text{Coal Costs}_{2005} * (1 + 0.5\%)$$

$$+ \text{Natural Gas Cost}_{2005} * (\text{NG Price}_{20006} / \text{NG Price}_{2005})$$

The fuel costs for coal and natural gas were taken from the Base ASC model numbers and escalated.

2.17.8 Public Utility Exchange Cost Forecasts

The following calculations were used to calculate the annual ASC forecast for the public utilities for the year 2006. In each subsequent year the subscript year will increase. The individual utility ASC Forecast Modes are shown in WP-07-E-BPA-05B, Section 4.12.2.

$$\text{Exchange Cost}_{2006} = ((\text{Exchange Cost}_{2005} - \text{Fuel Cost}_{2005}) * (1+\text{Inflation Deflator}_{2006}))$$

$$+ \quad \text{Fuel Cost}_{2006} - \text{Wholesale Revenue Credit/Purchase}_{2005} + \text{Addition BPA Purchases}_{2006}$$

$$- \text{Wholesale Revenue Credit/Purchase}_{2006}$$

$$\text{Fuel Cost}_{2006} = (\text{Natural Gas Cost}_{2005} * (\text{NG Price}_{2006}/\text{NG Price}_{2005}))$$

Additional BPA Purchases are the product of any known PF Block Purchases (MWh) and the current PF-02 Flat Block price of $27.5/MWh.

Wholesale Revenue Credit/Purchase was calculated by first performing a resource balance test for each year, then calculating a revenue credit if there is a surplus or a purchased power cost if there is a deficit. The Wholesale Revenue Credit/Purchase value is determined by the following calculations:

If Wholesale $aMW_{2006} < 0$

Wholesale Revenue $Credit/Purchase_{2006}$ = (Wholesale aMW_{2006} * 8760(Hours)) * Market $Rate_{2006}$

Else (Wholesale aMW_{2006} * 8760(Hours)) * Market $Rate_{2006}$ * Resale Credit Percent

Resale Credit Percent is percent of market rate that utility can obtain for wholesale revenue credits.

The following calculation tests a utility's load and resource balance:

Wholesale aMW_{2006} = Wholesale aMW_{2005} + Addition BPA Purchases aMW_{2006} - Load $Growth_{2006}$/8760(Hour)

Wholesale aMW_{2006} are the wholesale sales (MWh) in base ASC. The annual test in the ASC Forecast Model adjusted this number to be either positive or negative. If Wholesale aMW is positive, BPA assumed the utility has surplus to be sold in to the wholesale market. If Wholesale aMW is negative, BPA assumed to be buying power in the wholesale market. Unlike the IOUs, the public utilities do not have "for profit" trading floor activities. BPA assumed the following decision rules for increases in a utility's loads. First, the utility will use "known" purchase contracts from BPA, then will reduce market wholesale sales, and finally will make market purchases.

2.17.9 Escalation Rates

Table 4 below page 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,* WP-07-E-BPA-03. The inflation deflators are supplied by Global Insight, Inc. BPA has an annual subscription to this data service.

Table 4

Escalation Rates

	Annual Inflation Rate	*Annual Gas Price Forecast*	*Annual Market Price Forecast*
2006	1.0155	7.058	60.00
2007	1.0191	6.758	55.27
2008	1.0191	6.758	55.27
2009	1.0209	5.243	45.84
2010	1.0230	5.204	46.90
2011	1.0248	5.509	48.06
2012	1.0239	5.765	49.21
2013	1.0235	6.092	50.36

Table 5

Investor Owned ASC Forecasts

	2006	2007	2008	2009	2010	2011	2012	2013
Pacificorp								
ASC $ /Mwh	35.72	38.22	39.49	43.22	44.27	45.49	46.70	47.93
TRL Mw hours	23,444,716	23,535,382	23,826,270	24,021,202	24,281,110	24,560,665	24,953,550	25,340,392
Residential load	10,452,086	10,492,506	10,622,190	10,709,094	10,824,965	10,949,596	11,124,752	11,297,213
Portland General								
ASC $ /Mwh	43.27	46.79	48.06	50.12	51.17	52.56	53.85	55.20
TRL Mw hours	21,636,686	22,260,015	22,843,299	23,435,649	23,775,647	24,164,756	24,680,040	25,213,460
Residential load	8,854,990	9,110,092	9,348,806	9,591,230	9,730,377	9,889,623	10,100,507	10,318,814
Puget Sound Energy								
ASC $ /Mwh	46.23	47.21	47.96	48.91	50.00	51.29	52.58	53.82
TRL Mw hours	21,002,829	21,164,889	21,214,530	21,389,730	21,617,490	21,898,539	21,902,190	22,455,531
Residential load	10,574,764	10,656,360	10,681,354	10,769,566	10,884,241	11,025,747	11,027,585	11,306,188
Avista								
ASC $ /Mwh	42.42	44.95	46.21	47.86	48.89	50.15	51.37	52.62
TRL Mw hours	9,841,038	10,090,370	10,334,413	10,621,522	10,904,097	11,183,651	11,429,960	11,658,137
Residential load	3,927,518	4,027,025	4,124,422	4,239,006	4,351,780	4,463,349	4,561,650	4,652,714
Idaho Power								
ASC $ /Mwh	39.78	42.13	43.59	45.22	46.29	47.49	48.67	49.86
TRL Mw hours	15,798,551	16,157,437	16,530,678	16,904,676	17,261,296	17,609,604	17,947,335	18,289,599
Residential load	6,972,685	7,131,079	7,295,809	7,460,873	7,618,267	7,771,993	7,921,050	8,072,108
Northwestern Energy PNWR								
ASC $ /Mwh	58.11	61.16	62.83	64.77	65.72	66.82	67.88	68.95
TRL Mw hours	7,410,267	7,623,748	7,843,380	8,069,339	8,301,808	8,540,973	8,787,029	9,040,174
Residential load	2,787,012	2,867,303	2,949,907	3,034,890	3,122,322	3,212,273	3,304,815	3,400,023

Table 5 continued

Public Utility ASC Forecasts

	2006	2007	2008	2009	2010	2011	2012	2013
Clark County PUD								
ASC $ /Mwh	51.99	51.16	52.06	45.63	46.04	47.47	48.73	50.21
TRL Mw hours	4,859,698	4,833,248	4,839,260	4,830,782	4,861,906	4,877,456	4,900,128	4,909,829
Residential load	2,420,531	2,407,356	2,410,351	2,406,128	2,421,631	2,429,376	2,440,668	2,445,500
Utility #1								
ASC $ /Mwh	48.79	48.29	49.52	52.10	53.73	55.68	58.35	61.51
TRL Mw hours	1,976,804	1,986,670	1,996,180	2,002,705	2,018,877	2,028,198	2,044,414	2,058,979
Residential load	756,103	759,877	763,515	766,010	772,196	775,761	781,963	787,534
Utility #2								
ASC $ /Mwh	43.68	44.35	47.23	48.42	50.18	50.73	51.47	52.23
TRL Mw hours	934,014	953,985	971,242	993,928	1,013,899	1,033,870	1,050,905	1,073,813
Residential load	287,864	294,020	299,338	306,330	312,485	318,640	323,890	330,951
Utility #3								
ASC $ /Mwh	50.73	54.08	54.11	55.61	55.90	57.14	58.03	59.01
TRL Mw hours	1,388,898	1,407,294	1,416,492	1,444,086	1,471,680	1,471,680	1,490,076	1,511,711
Residential load	615,282	623,431	627,506	639,730	651,954	651,954	660,104	669,688
Utility #4								
ASC $ /Mwh	51.53	51.48	52.11	52.75	53.60	54.02	54.68	52.51
TRL Mw hours	759,736	772,258	774,765	777,314	776,785	782,748	785,329	830,579
Residential load	334,201	339,709	340,812	341,934	341,701	344,324	345,459	365,364
Utility #5								
ASC $ /Mwh	43.73	44.48	45.85	47.40	48.46	49.00	49.77	50.73
TRL Mw hours	7,077,527	6,958,702	7,026,879	7,089,821	7,130,803	7,484,488	7,708,269	7,823,636
Residential load	3,220,971	3,166,894	3,197,921	3,226,566	3,245,216	3,406,178	3,508,020	3,560,524

3. COST ALLOCATION AND RATE DESIGN IMPLEMENTATION

3.1 Rate-making Sequence

The rate-making methodology in the WPRDS includes a Cost of Service Analysis (COSA), a series of Rate Design Step adjustments, a Subscription Step, and a Slice Separation Step. The COSA assigns responsibility for BPA's generation revenue requirement to the various classes of service in accordance with generally accepted rate-making principles and in compliance with statutory directives governing BPA's ratemaking. The Rate Design Step adjustments to the allocated costs in the COSA are necessary to ensure that BPA recovers its test period revenue requirement while following its statutory rate directives. The Subscription Step takes the rates resulting from the Rate Design Step and makes adjustments to reflect BPA's Subscription contract obligations. The Slice Separation Step separates out the PF Slice product firm loads and allocated costs from the overall non-Slice PF loads and allocated costs.

3.2 Cost of Service Analysis (COSA)

The COSA allocates the test period generation revenue requirement that is determined in the Revenue Requirement Study, WP-07-E-BPA-02, to BPA's customer classes. The COSA apportions or "allocates" the test period generation 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.

Three major rate-making steps were completed in the process of determining BPA's total cost of service for power rates: (1) *functionalization* of costs between generation and transmission to develop the generation revenue requirement; (2) *classification* of costs between demand, energy, and load variance; and (3) *allocation* of costs to classes of service.

In this power rate case, BPA is determining power rates to be charged by BPA's PBL. Functionalization of costs between generation and transmission was performed in the development of BPA's generation revenue requirement. The remaining steps to determine BPA's cost of service for wholesale power--classification and allocation of costs--are performed in the COSA portion of the WPRDS Documentation, WP-07-E-BPA-05A.

3.2.1 PBL 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 rate-making. 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.

The Revenue Requirement Study, WP-07-E-BPA-02, is based on generation revenue and cost estimates for a three-year test period, FY 2007 through FY 2009. The revenue requirement from the Revenue Requirement Study is adjusted in the WPRDS COSA for projected balancing purchase power costs, system augmentation costs, and the functionalization of REP costs. For the three test years, the total adjusted generation revenue requirement is $7.420 billion. Adjusted annual functionalized revenue requirements used for rate calculations are shown in the WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Tables COSA 06 FY 2007 through COSA 06 FY 2009. Total adjusted functionalized revenue requirements for the five-year period are shown in the WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Table 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 F.E.R.C. ¶ 61,096 (1984), BPA has prepared a power repayment study specifically for the generation function. All costs to be recovered through FCRPS power rates functionalized to generation are used to develop the generation revenue requirement in this rate proposal.

The Revenue Requirement Study, WP-07-E-BPA-02, also includes demonstrations to show that proposed revenues are adequate to recover all generation 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 shown in the COSA: (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, geothermal, and competitive acquisition programs less the costs associated with the Idaho Falls and Cowlitz projects. Costs of purchased power from contracts from the early 1990s are included in the NR resource pool. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Tables COSA 06 for FY 2007 through FY 2009.

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 from the category of balancing power purchases. Projected balancing power purchases are needed to serve firm loads at the margin in months other than the spring fish migration period. The expense estimate for balancing power purchases included in the revenue requirement is adjusted in the COSA as a result of Risk Analysis Model (RiskMod) modeling to reflect projected operation of the FCRPS. *See,* WPRDS

Documentation, WP-07-E-BPA-05A, Section 3.8.2. Costs of balancing power purchases are characterized as FBS replacements and as such are included in, and allocated as, FBS costs. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Tables COSA 06 for FY 2007 through FY 2009.

3.2.1.2.3 System Augmentation. BPA is also proposing to acquire a small amount of resources beyond the inventory represented by the FBS 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 FBS 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 WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Tables COSA 06 and COSA 08.

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 an exchanging utility's exchangeable load. They are fully explained in section 2.17 above. The rate design adjustments that follow the COSA in the WPRDS, and use the results of the COSA are performed on that portion of the revenue requirement classified to power. Consequently, the REP cost that comes into the COSA with energy costs, demand costs, and transmission costs included must be functionalized to generation. In this way, REP costs are made to comport with all other PBL costs as they go through the rate design adjustment process. The functionalization of REP costs is shown in the WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Table COSA 07.

3.2.3 Classification. Classification in the WPRDS apportions generation costs between the demand, energy, and load variance components of electric power. This classification of the generation revenue requirement is shown in the WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Table COSA 08.

The classification methodology BPA uses is based on the marginal costs of the components of power and generally accepted rate-making procedures. BPA sets the price for demand using an adjusted marginal cost of demand. *See,* Section 2.2.1.2 of this Study for a detailed description. In addition, BPA sets the price of the Load Variance Rate using its adjusted marginal costs. *See,* Section 2.2.4, for a detailed description. Sales and revenues of these products are then forecasted. Forecast revenues associated with demand are classified to demand. Forecast revenues for load variance are deemed to be equal to the cost of Load Variance and therefore classified as such. Generation costs classified to energy are the residual of total generation costs not classified to demand or load variance. BPA continues this classification scheme in this rate case; 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 generation and classified to energy. Most of these revenue credits are associated with the operation of FBS resources and have the effect of reducing the FBS resource costs to be recovered by BPA's power rates.

3.2.4.1 COE and Reclamation Project Revenues. COE and Reclamation Project revenues are payments from owners of downstream projects to the COE and Reclamation for benefits received (*i.e.,* additional generation) from the storage reservoirs owned by the COE and Reclamation. These revenues are not subject to revision through rates and hence are a revenue credit. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Table 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 F&W 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,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Table 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,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Table COSA 09.

3.2.4.4 Irrigation Pumping Revenues. BPA receives a small amount of income from the delivery of pumping power at very low rates to Reclamation irrigation projects. While this revenue is not fixed, it totals less than $500,000 per year, depending upon the weather. This revenue is paid at the end of the year directly to the Treasury by Reclamation. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Table COSA 09.

3.2.4.5 Energy Services Business Revenues. BPA receives revenues associated with the activities of its Energy Services Business. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Table COSA 09.

3.2.4.6 Miscellaneous Revenues. Most of these estimated revenues are from contract administration, late fees, interest on late payments, and mitigation payments. These fees are not subject to change in the rate filing. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Table COSA 09.

3.2.5 PBL Ancillary and Reserve Services Revenues Credits. The PBL, 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,* Chapter 4 below. 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,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Table COSA 09.

3.2.6 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 planning load and resource balances prepared in the Load Resource Study, WP-07-E-BPA-01.

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.

For BPA's WP-07 Initial Proposal, 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,* Load Resource Study, WP-07-E-BPA-01, Appendix A. 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.

3.2.6.1 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 Load Resource Study, WP-07-E-BPA-01, and other data. From this ratemaking load and resource balance, service to each of the three rate pools from each of the resource pools is determined for the rate test period. Table ALLOCATE 01 shows the rate-making energy loads and resources by pools. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Table ALLOCATE 01.

3.2.6.2 Energy Allocation Factors. When service from each resource pool to each class of service has been identified, the amount of such service is the allocation factor for the resource pool. Resource pool costs are allocated to classes of service based on the proportions of their identified use of the resource pools to the total size (use) of the resource pool. The annual energy allocation factors for each resource pool are shown in the WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Table ALLOCATE 01. The Total Usage and Conservation allocation factors are the same and are based on the sum of the FBS, REP, and NR allocation factors. They are used to allocate costs and rate design adjustments to all firm energy loads. Allocated power costs are shown in the WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2 Table ALLOCATE 02.

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

3.2.6.3.1 Conservation Costs. The Northwest Power Act requires BPA to treat cost-effective conservation as an electric power resource in planning to meet the Administrator's obligations to serve loads. The "conservation" line item, as seen in the COSA 06 tables (S*ee,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2), 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 COSA 09 (S*ee,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2), reflects payments provided by other BPA organizations and Federal agencies for the energy efficiency services delivered.

3.2.6.3.2 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 rate-making process. The generation portion of these costs is determined in the Revenue Requirement Study, WP-07-E-BPA-02. The generation portion appears as BPA program costs. These costs, as seen in Table COSA 8 Table (S*ee,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2), are allocated uniformly to all customer classes based on the total usage allocation factors for energy.

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

The PNRR value found in the COSA 06 tables is the result of an iterative process between the RAM2007, the RiskMod, Non-Operating Risk Model (NORM) and the ToolKit models, *See,* Risk Analysis Study, WP-07-E-BPA-04. The iteration is initiated with a seed value for PNRR in COSA 06 of the RAM2007. The resultant rates are used in RiskMod to produce probability distributions. These distributions are then used in the ToolKit to produce a new PNRR value and ending cash reserve amounts for new COSA 06 tables. *See,* WPRDS Documentation, WP-07-E-BPA-05A. For further explanation of this iterative process, S*ee,* Doubleday, *et al*., WP-07-E-BPA-15.

3.2.7 COSA Results. The result of the COSA process is the allocation of the test period revenue requirements for power to classes of service served with firm power. Table ALLOCATE 02 summarizes the allocated generation power revenue requirement and the total allocated revenue requirement recoverable from power rate classes of service, including transmission costs allocated to the PBL, that are recoverable from these classes of service. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Table 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 Excess Revenue Adjustment The Excess Revenue Adjustment recognizes that revenues will be collected from certain classes of service to which costs are not allocated and credits these revenues to other customer classes. Projected secondary energy sales are the source of excess revenues.

3.3.1.1 Secondary Energy Sales On a planning basis and with system augmentation, BPA will have firm resources available to meet firm load obligations under 1937 water conditions. However, rates are set assuming that better than critical water conditions will occur and, therefore, secondary energy sales and revenues are projected. These sales and revenues are projected on the 50 water year run of the RiskMod model. *See,* Wagner, *et al.,* WP-02-E-BPA-14. The projected secondary energy revenue credits are allocated to firm loads so that BPA does not recover more than its revenue requirement.

The RiskMod model is used to project the level of secondary energy sales and revenues. BPA expects to sell secondary energy that will produce $1.729 billion in revenues over the three-year test period. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.3, Table RDS 11.

3.3.1.2 Allocation of Excess Revenues. Excess revenues are functionalized to generation and classified to energy. They are then allocated to loads served with Federal system resources (FBS and NR). The generation-related excess revenues are allocated in this manner because they are associated with secondary energy service and the cost of secondary energy is based on Federal resource costs only. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.3, Table 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 2007 to 2009 rate period, it will receive $281.6 million in revenues from the sale of firm power in various PNW and Southwest markets. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.3, Table RDS 17. BPA has allocated $1.4642 billion in generation costs to the firm power sold. BPA has allocated $387.4 million in revenue credits to the firm power sold. Therefore, there will be a revenue deficiency of $795.2 million over the three-year test period. This revenue deficiency of allocated costs in excess of revenues is charged to all firm power (PF, IP, NR) customers. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.3, Tables RDS 17 and 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 DSI rates will be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." Pursuant to Section 7(c)(2), the DSI rates are to be based on BPA's "applicable wholesale rates" to its preference customers and the "typical margins" included by those customers in their retail industrial rates. Section 7(c)(3) provides that the DSI rates are also to be adjusted to account for the value of power system reserves provided through contractual rights that allow BPA to restrict portions of the DSI load. This adjustment is typically made through a Value of Reserves (VOR) credit. To more accurately reflect the product the PBL may purchase from the DSI customers, the name has been changed to Supplemental Contingency Reserve Adjustment (SCRA). However, for this rate case, BPA is not proposing a uniform SCRA credit to be applied against DSI rates. *See,* Appendix B. Thus, the DSI rates are set equal to the applicable wholesale rate, plus a typical margin, subject to the DSI floor rate test and the outcome of the Section 7(b)(2) rate test. *See,* Sections 3.3.4. and 3.3.5.

The applicable wholesale rate is the PF rate (in combination with the NR rate if new NLSLs were projected for the test period) at the DSI load factor. The typical margin is based on the overhead costs that preference customers add to BPA's price of power in setting their retail industrial rates. The methods and calculations used to determine the typical margin are discussed in detail in Appendix A. The net margin is 0.573 mills/kWh. As previously stated, a zero SCRA credit is being forecast in this rate case. This net margin is added to the seasonal and diurnal PF energy charges. These adjusted PF 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. Because the allocation of the 7(c)(2) delta changes the PF rate upon which the IP rate is based, the entire process is repeated with the revised PF rate from the previous iteration until the size of the 7(c)(2) delta does not change when a successive iteration is performed. This process is accomplished through an algebraic solution. *See,* WPRDS Documentation, WP-07-E BPA-05A, Section 2.3, Table RDS 21.

BPA does not expect to provide power under the IP rate schedule for this rate period. Therefore, the size of the 7(c)(2) delta for the three-year test period is insignificant for rate-making purposes. However, the calculation is shown for continuity of methodology purposes.

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 and PF Exchange rate.

The Section 7(b)(2) Rate Test Study, WP-07-E-BPA-06, indicates the 7(b)(2) rate test has triggered and the PF rate applicable to BPA's preference customers must be adjusted downward. The amount of downward adjustment needed is implemented through a reduction of the PF Preference rate in mills/kWh. Historically, it is at this point in the rate-making process that BPA would make three adjustments in the rate design sequence to provide this protection to its preference customers and allocate the costs of the rate protection.

First, the PF preference customer class is given a credit, which reduces its rate, by the amount of the protection indicated in the Section 7(b)(2) Rate Test Study, WP-07-E-BPA-06. The 0.7 mills/kWh protection amount would result in a credit of $125.8 million to these customers. The cost of providing this protection would be allocated to the remaining firm power customers in the rate design process (PF Exchange, IP, and NR). *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.3, Table RDS 30.

The second adjustment is the 7(b)(2) Industrial Adjustment. The amount of this adjustment is the value of a recalculated 7(c)(2) delta at the lower PF Preference rate. Because there is no IP load forecast for this rate period, the amount of the new 7(c)(2) delta is $0.0. If there had been a non-zero amount, it would have been allocated to the PF Exchange customer class and to the NR customer class. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.3, Table RDS 33.

If BPA had forecast that some utilities would be participating in the REP, a third adjustment would have been necessary to allocate an increase in the gross Residential Exchange costs resulting from the bifurcation of the PF rate, causing the PF Exchange Program rate to be higher than the average combined rate before the bifurcation. This would have resulted in higher Residential Exchange ASCs for any deeming utilities and the gross costs of the Residential Exchange would have been recalculated. In that case, any increase in such costs can only be allocated to the PF Exchange rate and the NR rate. Because BPA has forecast no active exchange load, as well as no industrial firm load, this rate adjustment is not necessary in this rate case.

In this rate proceeding, BPA has forecast zero loads for the PF Exchange, IP, and NR rate pools. Therefore, even though the 7(b)(2) rate test has triggered and a reallocation of $125.8 million for the rate period is indicated, there are no loads over which BPA can reallocate this PF preference protection amount. Section 7(a)(1) of the Northwest Power Act requires BPA to recover the costs of producing and transmitting its power though its rates. With no loads other than PF preference loads, no reallocation of the PF preference protection amount could be performed. If BPA had forecast firm load other than PF preference firm load and after the three 7(b)(2) adjustments were made (in the absence of a need for a DSI floor rate adjustment), BPA would then be able to calculate Rate Design Step energy rates for the firm power classes of service. If the DSI rate falls below the floor rate, however, one final adjustment is necessary.

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

The first step in calculating the floor rate is to apply the IP-83 Standard rate charges to test period (FY 2007-2009) DSI billing determinants. Although the energy billing determinants used for this calculation are identical to the energy billing determinants for the proposed rates, the demand billing determinants are different. The IP-83 Demand Charges are applied to billing determinants based on non-coincidental demand. The resulting revenue figure is then divided by total IP test period loads to arrive at an average rate in mills/kWh. This rate is reduced by an Exchange Cost Adjustment and a deferral that were included in the IP-83 rate. Both adjustments are made on a mills/kWh basis.

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

These calculations result in an undelivered DSI floor rate of 20.98 mills/kWh. The floor rate is then applied to the test period DSI billing determinants to determine floor rate revenues.

Revenues at the proposed IP rate charges are compared to revenues at the floor rate. Because the proposed IP rate revenues are greater than the floor rate revenues, no adjustment is necessary to the Rate Design Step to the IP rate. Tables RDS 23 and RDS 24 show the DSI floor rate calculation. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.3. With no DSI floor adjustment required, the final Rate Design Step allocations are shown in Table RDS 33 of the WPRDS Documentation, WP-07-E-BPA-05A, Section 2.3.

3.4 Subscription Step Adjustments

The cost allocations and rates from the Rate Design Step, above, are used as the initial starting values for the Subscription Step cost allocations.

3.4.1 Subscription Step Cost Allocation. The costs and rate in the Rate Design Step include costs associated with IOU participation in the REP and do not include costs associated with the IOU REP Settlements. The Subscription Step replaces any net cost of the traditional IOU REP that was calculated in the Rate Design Step and with the forecast costs of the IOU REP Settlements. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.3, Table SUBSCR 01.

3.5 Slice Cost Calculation

Slice is a requirements power product. Purchasers of Slice (participants) are entitled to a fixed percentage of the generation from the FCRPS. Because Slice is calculated as a percentage of the FCRPS, the actual MWh delivered to the Slice participant will vary throughout the year. During certain periods of the year and under certain water conditions, the power delivered will exceed the Slice participant's firm net requirements and may at times exceed the Slice participant's actual firm load. As a consequence, Slice entails a sale of both requirements and surplus power products. *See,* section 2.14 above for a discussion of the Slice Product and rate.

Slice participants assume the obligation to pay a percentage of BPA's costs, rather than pay a set rate per MW or MWh. The Slice participant's obligation to pay is equal to the percentage of the FCRPS that the Slice participant 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 PBL revenue requirement identified in this rate case with certain limited exceptions. For the calculation of the cost of the Slice product in dollars per month for each percent of the Federal system, S*ee,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.3, Table Slice Cost 01.

3.6 Slice PF Product Separation Step

In the Rate Design and Subscription steps, costs were allocated to the various rate pools, including the PF Preference rate pool that contained all firm PF Preference load. The Slice Separation Step separates out the PF Slice product revenues and firm loads from the overall PF Preference rate pool, leaving the costs that must be covered by the remaining non-Slice product PF Preference load through posted PF Preference energy, demand, and load variance charges. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.3, Table SLICESEP 01.

3.6.1 Slice Separation IOU REP Settlement Cost Adjustment. After the separation of Slice related revenues and loads from the PF Preference load pool, the calculated non-Slice PF Preference rate may be different than the PF Preference rate previously calculated using the entire PF Preference load and costs. Therefore, a final calculation of the IOU REP Settlement benefits is necessary. Any change in annual IOU REP Settlement benefits is allocated to both Slice and non-Slice PF loads. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.3, Table SLICESEP 02.

4. INTER-BUSINESS LINE REVENUES AND EXPENSES

This section explains the cost allocation of inter-business line revenues and expenses between BPA PBL and TBL. PBL is compensated through a Memorandum of Agreement for the generation inputs PBL provides to TBL for the provision of ancillary services sold to transmission contract holders. The first section describes the method and assumptions BPA uses to allocate costs to the generation inputs for ancillary services. The second section describes the method for cost allocation to Generation Dropping and Station Service. The third section describes the segmentation costs of COE and Reclamation transmission facilities.

4.1 Generation Inputs for Ancillary Services

This section describes the method BPA proposes to use to allocate costs to the generation inputs for ancillary services. 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 proposed methodology, identify the assumptions used in the methodology, and establish the generation input rate that is applied to determine the annual revenue forecast.

4.1.1 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 Reserve 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 once a year to meet their entire reserve obligation to the control area. As the control area operator, TBL must provide Operating Reserves to any transmission customer that does not self-supply or third-party supply. In these instances, TBL acquires the generation inputs for these Operating Reserves from PBL.

4.1.1.1 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 requires that each control area maintain Spinning Reserves equal to a minimum of 50 percent of its Operating Reserve obligation.

4.1.1.2 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 Reserve obligation minus its Spinning Reserves.

4.1.1.3 General Methodology. The methodology to establish the 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 of Operating Reserves.

4.1.1.4 Calculation of Unit Cost of Operating Reserves Generation Input. The steps to calculate the unit cost of Operating Reserves Generation Input are described below. First, BPA calculated the average annual cost of all FCRPS hydro projects based on the embedded costs of hydro, less Generation Supplied Reactive revenue, to be $834 million. *See,* Section 4.4.1, Table 1 of the WPRDS Documentation, WP-07-E-BPA-05B.

Second, BPA calculated the forecast average system uses (9,217 MW generation plus 420 MW Spinning and Supplemental Operating Reserve obligation, plus 350 MW Regulating Reserve obligation) of 9,987 MW. *See,* Section 4.4.1, Table 1B of the WPRDS Documentation, WP-07-E-BPA-05B. Third, calculated 4.2% 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 ad adjusted power revenue requirement of $35 million per year that reflects generation input costs provided for Operating Reserves. Finally, PBL determined the per-unit generation input rate for Operating Reserves by dividing the adjusted power revenue requirement of $35 million by the total PBL Operating Reserve Obligation (420 MW * 12 months * 1000) to yield $6.96 kW-month per unit cost.

4.1.2 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 PBL 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	270 MW
(3) Total PBL Reserve Obligation	420 MW
(4) Total BPA Control Area Regulating Reserve Obligation	350 MW

4.1.3 PBL Revenue Forecast for Operating Reserves Generation Input

PBL proposes to apply the assumptions in Section 4.1.2. to calculate an estimated annual revenue forecast of $35 million for the generation inputs provided to TBL for provision of Operating Reserves, net of self-supply and third-party supply. This revenue forecast reflects 420 MW of average hourly generation inputs supplied to TBL, multiplied by a rate of $6.96 kW-month, multiplied by 12 months, multiplied by 1,000.

4.1.4 Regulating Reserves

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

4.1.4.1 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, TBL currently estimates this requirement to be an annual average of 350 MW.

4.1.4.2 General Methodology. The methodology to establish the 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.

4.1.4.3 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.

4.1.4.4 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,* Section 4.4.2, Figure 1, Tables 2, 3, and 4 of the WPRDS Documentation, WP-07-

E-BPA-05B. 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 prior rate case, 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,* Section 4.4.2, Table 3 of the WPRDS Documentation, WP-07-E-BPA-05B.

4.1.4.5 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 (kW). Interviews taken previously from the O&M staffs at Bonneville, Grand Coulee, and the lower Snake Dams for the WP-02 rate case 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 kW. *See,* Section 4.4.2, Table 3 of the WPRDS Documentation, WP-07-E-BPA-05B.

4.1.4.6 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 MW 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 MW at peak efficiency by the smaller of the plus or minus generation range. Each separate multiplier is then weighted by the corresponding number of MWs 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,* Section 4.4.2, Table 4 of the WPRDS Documentation, WP-07-E-BPA-05B.

4.1.4.7 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 $722 million. *See,* Section 4.4.2, Table 1 of the WPRDS Documentation, WP-07-E-BPA-05B. The forecasted average system use for the Big 10 (generation, Spinning and Supplemental Operating Reserve obligation, and the Regulating Reserve obligation) is 8,927 MW. *See,* Section 4.4.2, Table 1B of the WPRDS Documentation, WP-07-E-BPA-05B. 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 forecasted to be 350 MW. Of this amount, the TBL 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 $8.29/kW-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 Generation Input rate of $8.29/kW-month equals the Big 10 base cost of $6.74/kW-month plus the AGC Adder of $1.55/kW-month.

4.1.4.8 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	270 MW
(3) Total PBL Reserve Obligation	420 MW
(4) Total BPA Control Area Regulating Reserve Obligation	350 MW
(5) Total TBL Regulating Reserve Obligation	150 MW

4.1.4.9 PBL Revenue Forecast for Regulating Reserves Generation Input. PBL proposes to apply the assumptions in Section 4.1.4.8 to develop a generation input for Regulating Reserves that consequently will establish the annual revenue forecast.

PBL proposes a generation input rate for Regulating Reserves of $8.29/kW-mo. The base generation input charge is calculated by the adjusted power revenue requirement, for the Big 10 hydro projects, of $28,326,274 divided by the PBL reserve obligation (350 MW * 12 months * 1,000) = $6.74/kW-mo plus the AGC Adder of $1.55/kW-mo.

PBL proposes an annual revenue forecast for Regulating Reserves of $14,922,000. This forecast is calculated by the total TBL Regulating Reserve obligation of 150 MW multiplied by the per unit rate ($8.29/kW-mo * 12 months *1,000).

4.1.5 Generation Supplied Reactive and Voltage Control

This section describes the method BPA is proposing to allocate power costs to the generation input for generation supplied reactive power and voltage control.

4.1.5.1 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 as the provision of reactive capacity, energy, and maneuverability from a resource in order to control voltages to support transmission system reliability. Through Order 888, FERC has identified this function as an ancillary service that a transmission provider must offer. In order to provide this ancillary service, the transmission provider must acquire this service from a generation source as a generation input.

4.1.5.2 General Methodology 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 average annual cost to provide the generation input for Reactive Power and Voltage Control is $26 million. *See,* Section 4.4.3, Table 1 of the WPRDS Documentation, WP-07-E-BPA-05B.

4.1.5.3 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.

4.1.5.3.1 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%. 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,* Section 4.4.3, Tables 4, 5, and 6 of the WPRDS Documentation, WP-07-E-BPS-05B.

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% 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,* Section 4.4.3, Tables 4 and 5 of the WPRDS Documentation, WP-07-E-BPA-05B.

4.1.5.3.2 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 thru 2009. The projected activities include Electrical Plant, Transmission modifications associated with Generation Integration and 50% Accessory Equipment on a plant-by-plant basis. The projected expenditures are used to determine the percent 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 COE and Reclamation hydro projects on a plant-by-plant basis to determine net electrical plant replacements. *See,* Section 4.4.3, Table 6 of the WPRDS Documentation, WP-07-E-BPA-05B.

4.1.5.3.3 CGS Electrical Plant. The Energy Northwest staff provided investment and depreciation data for items identified as electrical plant in the WP-02 rate case. This data is valid for the current rate case, because there have been no significant modifications to the CGS. BPA retains the 0.74 ratio of net electrical plant divided by net total plant as determined previously. The resulting ratio of 0.74 is then used as an allocator in the Revenue Requirement Study, WP-07-E-BPA-02, to determine annual costs of CGS electrical plant. *See,* Section 4.4.3, Table 8 of the WPRDS Documentation, WP-07-E-BPA-05B.

4.1.5.3.4 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 rate case. For the WP-02 rate case, 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% for COE and 45% for Reclamation. These percentages are applied to budgeted O&M for this Initial Proposal.

4.1.5.3.5 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-E-BPA-02, to determine the portion of O&M to be allocated to electrical plant. *See,* Section 4.4.3, Table 8 of the WPRDS Documentation, WP-07-E-BPA-05B.

4.1.5.4 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.

4.1.5.5 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 TBL 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 TBL is $372,000 per year. For energy consumption BPA forecasts 136,337 MWh of energy. Applying an estimated average PF rate of 30 mills/kWh to the energy consumed results in a total cost of $4,090,116. *See,* Section 4.4.3, Tables 1 and 12 of the WPRDS Documentation, WP-07-E-BPA-05B.

4.1.5.6 Reactive Energy Losses. Real power (MW) 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 rate of 30 mills/kWh is used to price the power, resulting in a total cost of $2,149,000. *See,* Section 4.4.3, Tables 1 and 13 of the WPRDS Documentation, WP-07-E-BPA-05B.

4.1.5.7 Summary – Costs Assigned to TBL 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 TBL Settlement for FY 2007 and forecasted for FY 2008 and 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 $18,151,000 for COE and Reclamation and $179,000 for CGS. In addition to these, $364,000 costs for synchronous condenser modifications, $4.1 million costs for synchronous condenser power consumption, and $2.15 million costs for real energy losses are added to result in the total proposed annual cost allocation of $24,933,000 to TBL for generation supplied reactive and voltage control. *See,* Section 4.4.3, Table 1 of the WPRDS Documentation, WP-07-E-BPA-05B.

4.2 Generation Inputs for Other Services

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

4.2.1 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, the PBL is requested by the TBL to instantaneously drop large increments of generation (600 MW plus). 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, the PBL can most expeditiously provide this service by dropping one of the Grand Coulee Third Powerhouse hydroelectric units (each of which exceeds 600 MW capacity).

The PBL 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.

4.2.1.1 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.

4.2.1.1.1 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,* Section 4.4.4, Table 1 of the WPRDS Documentation, WP-07-E-BPA-05B. 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,* Section 4.4.4, Table 2 of the WPRDS Documentation, WP-07-E-BPA-05B.

4.2.1.1.2 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 was 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,* Section 4.4.4, Table 3 of the WPRDS Documentation, WP-07-E-BPA-05B.

4.2.1.2 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 major cost components that would be affected by a generation drop: reduced time between major overhauls or replacement, and increased routine maintenance. 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,* Section 4.4.4, Table 4 of the WPRDS Documentation, WP-07-E-BPA-05B.

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.

4.2.2 Station Service

Station Service refers to real power taken directly off the BPA power system for use by TBL at substations and other facilities. The TBL 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 the PBL for use at BPA substations. This does not include Station Service that is being purchased by the TBL from another utility or supplied by another utility through contractual arrangements.

4.2.2.1 General Methodology. BPA proposes to allocate costs to Station Service in a manner that estimates the amount of kWh 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 times 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,* Section 4.4.5, Table 1 of the WPRDS Documentation, WP-07-E-BPA-05B.

4.2.2.2 Determining Costs to Allocate to Station Service. The average load factor of 9.4 percent times the installed primary Station Service capacity times the number of hours in the month determines the estimated Station Service kWh usage for each substation. The historic average Station Service kWh 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-month or an average of 8.8 MW. BPA proposes to apply the estimated average PF rate of 30 mills/kWh, to price the power, at a total cost of $2.29 million per year. *See,* Section 4.4.5, Table 1 of the WPRDS Documentation, WP-07-E-BPA-05B.

4.3 Segmentation of COE/Reclamation Transmission Facilities

This section covers segmentation of COE/Reclamation Transmission Facilities. The analysis covers transmission facilities owned by the COE and the 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/ Reclamation transmission investment is identified and segmented so that the annual cost of these facilities may be developed and a portion assigned to TBL.

BPA is proposing to assign the COE/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/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.

4.3.1 Generation Integration (GI)

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

4.3.2 Integrated Network

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

4.3.3 Utility Delivery

Utility delivery facilities are those facilities that deliver power to BPA public utility customers at voltages less than 34.5 kV. BPA proposes to continue to assign these costs to transmission. The segmentation of these facilities is consistent with the segment definitions used in TBL's most recent segmentation study. *See,* 2002 Final Transmission Proposal 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/Reclamation transmission facilities may be placed in the appropriate transmission segment in the future Power rates cases..

4.3.4 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,* Section 4.5.1, Table 1 of the WPRDS Documentation, WP-07-E-BPA-05B.

4.3.5 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,* Section 4.5.2, Tables 1-3 of the WPRDS Documentation, WP-07-E-BPA-05B, for the Columbia Basin project (Grand Coulee). *See,* Section 4.5.3, Table 1 of the WPRDS Documentation, WP-07-E-BPA-05B, for the other Reclamation projects. The available Reclamation investment data did not breakdown costs to the equipment level. To develop investment by segment(s) 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,* Section 4.5.3, Table 1 of the WPRDS Documentation, WP-07-E-BPA-05B.

5. REVENUE FORECAST

This section describes the revenue forecast prepared for the BPA WP-07 Initial Proposal and presents the results of that forecast.

5.1 Overview

The revenue forecast is BPA expected level of sales and revenue for the period, FY 2005 through 2009. BPA prepares two revenue forecasts. One uses current rates; and the other uses the proposed rates. These revenue forecasts are used to demonstrate that existing rates do not cover BPA revenue requirement and that proposed rates do cover BPA revenue requirement. The revenue test is described in the Revenue Requirement Study, WP-07-E-BPA-02, chapter 5.1.1. The base rates placed in effect October 1, 2001, before application of the LB CRAC, are used in the calculation of revenues at current rates for FY 2007 through 2009. The proposed rates are developed in the WPRDS, based on the loads forecast in the BPA Initial Proposal. The proposed rates are then applied to those loads to create one revenue forecast from FY 2007 through FY 2009.

5.2 Sources of BPA Revenue

PBL 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, Federal agencies, IOUs, and DSI customers. In FY 2004 this revenue totaled $1,711 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 for upstream benefits from owners of downstream projects. In FY 2004 the sum of these totaled $380 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 power. In FY 2004, short-term power sales generated revenue of $592 million, excluding bookouts. Bookouts are 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 are required to be subtracted according to GAAP, but the dollars still change hands as if the transaction occurred. Bookouts in FY 2004 totaled $212 million.

The fourth source of revenue is from the sale of generation inputs for ancillary and reserve products. The major component of this group is revenues from generation inputs sold to the TBL. In FY 2004, revenue from all generation inputs and reserve product sales was $77 million.

The last revenue source is revenue credits from the U. S. Treasury and revenues from miscellaneous sources. These 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 2004, these credits and revenue from other miscellaneous sources totaled $99 million.

5.2.1 Subscription Sales for FY 2007-2009

Sales of firm power under Subscription contracts are the basic products that the proposed rates are designed for. Most of BPA firm power will be sold under these contracts. The revenue from these contracts is estimated by applying the current PF-02, and IP-02 rates (or the proposed PF-07, and IP-07 rates) to the projected billing determinants. The LDD was also taken into consideration. The CRC is reflected in BPA expenses rather than in the revenues, even though it is included with the rate schedules. When applying current rates to these sales, the revenue from these sales averages $1,519 million per year for the rate period. When applying proposed rates to these sales, the revenue averages $1,864 million per year for the rate period.

5.2.2 Contractual Formula Rates

Some of BPA's contracts include contractually specified formulas for calculating rates. These rates are based on a variety of factors including increases in the PF rate, increases in the NR 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 from FY 2007-2009, or until the contracts expire. Revenue from PBL in-region and out-of-region long-term contract sales is forecast to average $142 million per year for FY 2007-2009. *See,* WPRDS Documentation, Section 3.2 WP-07-E-BPA-05A.

5.2.3 Short-Term Market Sales and Power Purchases

For rate development purposes, BPA projects firm loads based upon critical (*i.e.,* 1937) water conditions. The revenue forecast reflects BPA's sales of energy created by streamflows 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 the entire year. Revenue from short-term market sales is projected to average about $576 million per year during the FY 2007-2009 rate period. *See,* WPRDS Documentation, Section 3.6.1 and Section 3.6.2, WP-07-E-BPA-05A.

5.2.3.1 Short-term Market Sales and Purchases. The calculation of short-term market sales begins by calculating monthly HLH and LLH energy surpluses and deficits in the RiskMod model. This analysis, referred to as the 50-year water 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), and load forecast studies, 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.

The 50-year water 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 forecasted Federal hydro generation for 50 historical water years under current hydro operation constraints. The 50 historical water years cover a broad spectrum of streamflow conditions from very dry to very wet. The results of the 50-year water run of RiskMod and the resulting balancing sales and purchases are shown in Sections 3.8.1 and 3.8.2 of the WPRDS Documentation, WP-07-E-BPA-05A.

5.2.3.2 Short-Term Market Revenues and Purchased Power Expense. 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-year water run of RiskMod. HLH and LLH prices used in the analysis are from AURORA. *See,* MPFS Documentation, WP-07-E-BPA-03A. BPA forecasts revenue from short-term sales will average $576 million per year during the rate period. *See,* Section 3.8.1 of WPRDS Documentation, WP-07-E-BPA-05A.

BPA projects that expenses associated with short-term purchases will average $81 million per year during the rate period. The forecast revenues from RiskMod for short-term market sales and purchased power expenses are noted in Sections 3.8.1 and 3.8.2 respectively of the WPRDS Documentation, WP-07-E-BPA-05A.

5.2.3.3 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 that BPA will receive. Market prices used to estimate the 4(h)(10)(C) operational credits were the same market prices used to estimate short-term surplus market sales revenues and purchased power expenses. BPA determined the additional purchased power costs of the fish and wildlife recovery programs by comparing purchased power expenses associated with: FCRPS operations before the restrictions were placed on river operations with FCRPS operations using current restrictions. 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 average $76 million per year during the rate period. The Section 4(h)(10)(C) credit calculations are shown in Section 3.8 of the WPRDS Documentation, WP-07-E-BPA-05A.

The Treasury credit for the Colville Settlement is set in 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 TBL that contain a generation component includes: Load Regulation, Control Area Reserves, Transmission Losses, Remedial Action, Reactive Power, and Energy Imbalance. Also, the PBL receives revenues from Reserve Services it provides to others. In FY 2004, revenue from ancillary products totaled $75 million, and revenue received from the sale of reserve services totaled $1 million. During the rate period, these revenues are expected to total $86 million and $1 million respectively. *See,* Section 3.9 of WPRDS Documentation, WP-07-E-BPA-05A.

5.2.5 Energy Efficiency

BPA projects revenues of about $13 million per year from the sale of energy efficiency products and services. Energy efficiency revenues are documented in BPA budget estimates prepared in 2005. Energy Efficiency revenues are in Section 3.10 of WPRDS Documentation, WP-07-E-BPA-05A.

5.2.6 Low Density Discount. The calculation of the LDD for a representative but unidentified customer is shown in Section 3.11 of WPRDS Documentation, WP-07-E-BPA-05A. The calculation is compared to the output from the RFA database to demonstrate how the LDD calculations are done. *See,* Section 2.9 for a description of the LDD methodology.

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, NR, and FPS sales. The energy load forecasts used in this rate proposal are documented in the LRS, *See,* WP-07-E-BPA-01, and LRS Documentation, WP-07-E-BPA-01A.

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 firm 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, that determination was made separately and the revenues were summed and added to the forecast. The sales made under regional Pre-Subscription FPS contracts were multiplied by the specific contract rate. Since these contracts contain confidential information the billing determinants and revenues were 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 expected revenue from these contracts. Revenues from long-term contract sales were calculated by applying the contract rates to these contracts in the same manner as the revenues were calculated from pre-subscription contracts. These contracts also contain confidential information therefore the contract revenues were summed and displayed together. Revenues from miscellaneous products and services and ancillary and reserve power products were added to the power revenues. Documentation of Ancillary and Reserve products is contained in WPRDS Documentation, *See,* WP-07-E-BPA-05B, Chapter 4.

5.4.1 Other Factors Affecting Forecasted Revenues. Other factors affecting forecasted revenues include the LDD, and irrigation mitigation sales, which are described below.

5.4.1.1 Low Density Discount (LDD). The LDD is projected to be about $18 million per year and is expected to be larger during the proposed rate period than in the current rate period because of increased qualifying loads due to expiration of most pre-subscription contracts.

5.4.1.2 Operating Reserves Credit (ORC). The ORC is a credit against revenues. The ORC is $0.89/MWH. The total ORC is projected to be about $35 million per year. The costs of the ORC will be offset by OR revenue PBL receives from TBL. A complete discussion of the ORC can be found in Section 2.3 above.

5.4.1.3 Mitigation Adjustment. Sales to irrigation loads are expected to total 153 aMW and the revenue from sales to these loads is received from contractually specified FPS rates that are lower than the PF rate, but rates for sales under these contracts will increase by the amount of the PF rate increase.

5.5 FY 2005 through FY 2006 Revenue

Forecast revenue using current rates for FY 2005 through 2006 in shown in Section 3.1 and 3.6.1 respectively of the WPRDS Documentation, WP-07-E-BPA-05A. Revenue in FY 2005, excluding bookouts, is projected to total $2,918 million. Revenue in FY 2006 is expected to total $2,993 million. Revenue from firm power sales to public utilities and Federal customers at the PF-02 and FPS-96R rates is projected to total $1,723 million in FY 2005, and $1,746 million in FY 2006.

Revenue from firm power sales to DSI customers under the IP-02 and FPS-96R rates is projected to be $75 million in FY 2005 and in FY 2006.

Long-term surplus contract revenue, 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 $154 million in FY 2005, and $128 million in FY 2006. The decline in revenue occurs because several of contracts expire during this period.

Revenue from the sale of generation inputs for ancillary and reserve products are projected to be $74 million in FY 2005, and $71 million in FY 2006.

Revenue from Section 4(h)(10)(C) credits are projected to be $53 million in FY 2005, and $89 million in FY 2006. Credits are based on actual water conditions in FY 2005. 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 revenue from the Energy Service activities and other sources were $11 million in FY 2004, and are projected to be $12 million in FY 2005 and $13 million in FY 2006.

5.6 Revenue for FY 2007 through 2009

Forecast revenue under current rates for the rate period, FY 2007 - 2009, are found in Section 3.6.1 of the WPRDS Documentation, WP-07-E-BPA-05A, and revenues forecasted under proposed rates for the FY 2007 - 2009 rate period are found in section 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 2007 through 2009 at Current Rates

Revenue estimated under current 2002 rates is shown in Section 3.6.1 of the WPRDS Documentation, WP-07-E-BPA-05A. Total revenue from all sources is projected to be $2,473 million in FY 2007, $2,396 million in FY 2008 and $2,351 million in FY 2009.

5.6.2 Revenues for FY 2007 through 2009 at Proposed Rates

Revenue estimated under proposed rates is shown in Section 3.6.2 of the WPRDS Documentation, WP-07-E-BPA-05A. Revenue at proposed rates is projected to be $2,834 million in FY 2007, $2,755 million in FY 2008, and $2,703 million in FY 2009.

6. RATE SCHEDULE DESCRIPTIONS

The wholesale power rates developed in the WPRDS are presented in the WPRS. The WPRS, WP-07-E-BPA-07, includes four sections. The first section contains the WPRS. Each rate schedule states to whom the rate schedule is available, rates for the products offered under the schedule, billing factors, and references to sections of the GRSPs that apply to that rate schedule. The WPRS also state appropriate transmission purchasing policies for power customers. The GTA Delivery Charge is also included. The second section contains the 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. The third section contains a reprint of the 2002 Slice Methodology, and the last sentence contains instructions for the LB CRAC True-Up carried over from the 2002 rate case.

Purchases under the PF-07, NR-07, and IP-07 rates are subject to the CRAC/DDC, the CRC, and the GEP. PF-07 and NR-07 are also subject to the ORC. The Slice Product will be subject to the CRC and the ORC; however, it will not be subject to the CRAC, DDC or the GEP. In addition, the PF Exchange Program rate will not be subject to the CRC, the ORC, or the GEP.

6.1 Priority Firm Power Rate, PF-07

The PF-07 rate schedule replaces the PF-02 rate schedule. The PF-07 rate schedule is available for the purchase of power by public bodies, cooperatives, Federal agencies, and utilities participating in the Residential Exchange under Section 5(c) of the Northwest Power Act. PF must be used to meet the purchasers' firm loads within the PNW.

The PF-07 rate schedule includes sections applicable to different types of purchasers under the 2002 Subscription Contracts and the Residential Purchase and Sale Agreement (RPSA). Rates for PF Demand and Energy, Load Variance, and Slice have been developed. 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. Residential Exchange customers may purchase under the REP.

The PF-07 Demand Rate is monthly differentiated. The PF-07 Energy Rates are monthly and diurnally differentiated. *See*, Sections 2.1 and 2.2 above that describe these methods.

Most purchases under the PF-07 rate schedule are subject to certain provisions of the GRSPs, including among others 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 Chapter 2 of this Study. Purchases under the PF-07 rate schedule are subject to the BPA billing provisions.

6.1.1 Operating Reserves Credit (ORC)

The Operating Reserves Credit is a new GRSP added to the PF-07 (except for PF Exchange Program Power), and NR-07 rate schedules. The ORC applies to firm power requirements service to regional firm load when the customer also purchases Operating Reserves from BPA's TBL either through an annual option or by choosing a transmission contract that explicitly requires the purchase of Operating Reserves from the TBL. *See,* Section 2.3 for further information.

6.1.2 Conservation Rate Credit (CRC)

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

6.2 New Resource Firm Power Rate (NR-07)

The NR-07 rate schedule replaces the NR-02 rate schedule. The NR-07 rate schedule is available for purchase of power by IOUs under net requirements contracts for resale to consumers, and to publicly owned utilities for New Large Single Loads (NLSLs). Similar to the PF-07 rate schedule, the NR-07 rate schedule includes sections applicable to different types of purchasers under the 2002 Contracts.

Products available under the NR-07 rate schedule include NR Demand and 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. The NR rate schedule specifies which transmission rate schedule(s) may apply to purchasers under the NR rate schedule. The NR-07 rate includes a monthly differentiated Demand Rate and monthly and diurnally differentiated Energy Rates for a three-year period. Purchases under the NR-07 rate schedule are subject to certain provisions of the GRSPs, including among others the LDD, the TAC, the UAI Charge, and in some cases, the Excess Factoring Charge. These are discussed in Chapter 2 above. Purchases under the NR-07 rate schedule are subject to BPA billing process.

6.3 Industrial Firm Power Rate (IP-07)

The IP-07 rate schedule replaces the IP-02 rate schedule. The IP-07 rate schedule is available to DSI customers for firm take-or-pay block power to be used in their industrial operations.

The IP-07 rate includes a monthly differentiated Demand Rate and energy rates that continue to be monthly and diurnally differentiated. Purchases under the IP-07 rate schedule may be for up to three years and are subject to provisions of the GRSPs, as listed in the rate schedule, including the Supplemental Contingency Reserves Adjustment (SCRA). The Load Variance Rate might be applicable if other products are purchased. Purchases under the IP-07 rate schedule are subject to BPA billing process.

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

The FPS-07 rate schedule is available for purchase of Firm Power, Capacity, Capacity without Energy, Supplemental Control Area Services, Shaping Services and Reservation and Rights to Change Services inside and outside the United States for the period ending September 30, 2009. The FPS-07 rate schedule supersedes the FPS-96R rate schedule. Similar to the FPS-96R rate, the FPS-07 contains a Contract rate and a Flexible rate. The design of the FPS-07 Contract rate differs from the FPS-96R Contract rate in that the energy, demand, and capacity rates are monthly and diurnally differentiated. See Sections 2.5 of this Study. The Flexible rate is a market-based rate that is flexible upward and downward, as mutually agreed by the contracting parties. The Flexible rate may have a demand component, an energy component, or both. Unbundled products also are available under the FPS-07 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-07 rate. Purchases under the FPS-07 rate schedule also are subject to BPA billing process.

APPENDIX A

7(C)(2) INDUSTRIAL MARGIN STUDY

APPENDIX A

7(C)(2) INDUSTRIAL MARGIN STUDY

1. INTRODUCTION

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

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

(1) the comparative size and character of the loads served;

(2) the relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions; and

(3) direct and indirect overhead costs, all as related to the delivery of power to industrial customers.

2. PURPOSE

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

3. METHODOLOGY

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

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

3.2 Typical Margin

The "typical margin" includes "other overhead costs" charged by the utilities in the study. BPA's power revenue requirements are accounted for in the PF rate charges, and distribution costs are included by adding in a charge for BPA's DSI delivery facilities. An overall margin is derived by weighting individual utility margins according to the proportion of industrial energy load served by each utility relative to total industrial energy load included in the study.

3.3 Margin Determination Factors

3.3.1 7(c)(2)(A) – Comparative Size and Character of the Loads Served. The data base used for the study includes utilities that serve at least one industrial customer with a peak demand of at least 3.5 MW.

3.3.2 7(c)(2)(B) – Relative Costs of Electric Capacity, Energy, Transmission, and Related Delivery Facilities Provided and Other Service Provisions. The utility margins in this study are based to the extent possible on utility cost of service analyses and incorporate allocated costs to the industrial customer class. The utilities segregate these costs into various cost categories, and only those categories considered to be appropriate margin costs are included in BPA's industrial margin calculation.

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

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

4. APPLICATION OF THE METHODOLOGY

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

4.1 Data Base

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

4.2 Utility Margins

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

4.3 Summary of Results

The final results of each step in the margin calculation for each utility are shown in Attachment A. The weighted industrial margin is 0.57 mills/kWh. This margin has been added to the PF-07 energy charges and applied to the forecasted DSI billing determinants.

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

Utility Number: # 2	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$6,906,015	$6,906,015				
Taxes Assigned to Purchased Power	$418,062					$418,062
Fixed Operations Expense						
Supervisory Operating Expense	$133,780			$133,780		
Labor/O&M	$142,500			$142,500		
Distribution/Operations	$7,500			$7,500		
Distribution/Maintenance	$12,000			$12,000		
Transmission Lines/Maintenance	$1,000		$1,000			
General Plant/Maintenance and Misc. Op. Exp.	$620			$620		
Administrative Expense	$67,600		$227	$67,373		
Taxes on Operations Expense	$88,699					$88,699
Transmisson Capital Expenditures	$150,000		$150,000			
Reserve Funding						
C&R Discount account (books out below)	$42,000	$42,000				
Emergency Reserve	$50,000		$168	$49,832		
Debt Service	$339,777		$1,142	$338,635		
Incomes						
Other revenue	-$5,000		-$17	-$4,983		
Collection of C&R	-$42,000	-$42,000				
Annual MWh Sales **205,902**						
Mills/kWh	$40.37	33.54	0.74	3.63	0.00	2.46

Utility Number: # 6(a)	Total Industrial (C.1)	Production	Transmission	Distribution	Other	Revenue taxes
Generation	$212,755	$212,755				
VAR (Generation)	$7,511	$7,511				
Purchased Power	$1,329,480	$1,329,480				
Transmission	$256,323		$256,323			
Distribution	$313,767			$436,091		
Customer Service, Accounts & Sales						
Meter reading	$443			$443		
Cust Records & Collection	$1,249			$1,249		
Low income	$25,004				$25,004	
Electric Marketing	$4,844				$4,844	
CILT on Retail Revenue (Contributions in Lieu of Taxes)	$137,028					$137,028
Secondary Cost of Service (customer facilities)	-$63	-$15	-$17	-$29	-$2	
Annual MWh Sales **46,850**						
Mills/kWh	51.45	33.08	5.47	9.34	0.64	2.93

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

Attachment B

Utility Number: # 6(c)	Total Industrial (A)	Production	Transmission	Distribution	Other	Revenue taxes
Generation	$2,008,219	$2,008,219				
VAR (Generation)	$70,559	$70,559				
Purchased Power	$10,868,335	$10,868,335				
Transmission	$2,565,406		$2,565,406			
Distribution	$2,553,347			$2,553,347		
Customer Service, Accounts & Sales						
Meter reading	$886			$886		
Cust Records & Collection	$3,748			$3,748		
Low income	$221,368				$221,368	
Electric Marketing	$69,743				$69,743	
CILT on Retail Revenue (Contributions in Lieu of Taxes)	$1,213,126					$1,213,126
Annual MWh Sales **463,006**						
Mills/kWh	42.28	27.96	5.54	5.53	0.63	2.62

Attachment B

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

Attachment B

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

Attachment B

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

Attachment B

Utility Number: # 24

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

Total energy sold Customer 1	34,829 MWh
Margin = $0.04/MWh	
Total energy sold Customer 2	232,582 MWh
Margin = $0.01/MWh	
Total energy sold Customer 3	870,068 MWh
Margin = $0.003/MWh	
Total energy sold Customer 4	20,930 MWh
Margin = $0.12/MWh	

Utility Number: # 27	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$4,525,439	$4,525,439				
Transmission	$30,213		$30,213			
Distribution	$3,114			$3,114		
Customer	$5,859				$5,859	
G&A	$51,689		$39,853	$4,108	$7,728	
Depreciation	$8,509		$7,714	$795		
Taxes	$1,202					$1,202
Interest	$2,348		$2,129	$219		
Other Expenses	$479		$369	$38	$72	
Overcollection in prior years	-$173		-$133	-$14	-$26	
Other Operating Revenue	-$43,292		-$33,379	-$3,440	-$6,473	
Annual MWh Sales **122,922**						
Mills/kWh	37.03	36.82	0.38	0.04	0.06	0.01

Utility Number: # 33

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

Total energy sold Customer 1	404.2 MWh
Amount $0.98/MWh applied	394 MWh
Amount $1.95/MWh applied	9,098 MWh
Margin = 1.004	

Total energy sold Customer 2	46.8 MWh
Amount $0.98/MWh applied	0
Amount $1.95/MWh applied	46.8 MWh
Margin = 0.98	

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

Attachment B

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

Attachment B

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

Attachment B

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

Attachment B

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

Attachment B

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

Attachment B

Utility Number: # 49	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$6,110,426	$6,110,426				
Sales from resale	-$292,173	-$292,173				
Transmission	$878,490		$878,490			
Distribution	$121,417			$121,417		
Customer Service, Accounts & Sales						
Meter Reading	$403			$403		
Cust. Records & Collection	$977			$977		
Info. & Insert Advertising	$101				$101	
Broadband	$1,306,623		$1,146,263	$160,227	$132	
Taxes	$423,071					$423,071
Debt Service	$574,049		$503,597	$70,394	$58	
Capital Improvements from Rates						
Transmission	$11,076		$11,076			
Substations	$75,240			$75,240		
Underground	$56,118			$56,118		
Vehicles	$4,763		$4,179	$584		
Customer - Dist Additions	$159,310			$159,310		
Customer - Transformers	$81,607			$81,607		
Customer - Meters & AMR	$192			$192		
Broadband	$33,143		$29,075	$4,064	$3	
Buildings	$3,314		$2,907	$406		
Improvements System	$203,258		$178,312	$24,925	$21	
Improvements General	$18,646		$16,358	$2,286	$2	
Administrative and General	$160,881		$141,136	$19,728	$16	
Less: Misc. Revenues						
Late Charges	-$75				-$75	
Misc. Service	-$85		-$74	-$10		
Rent from Electric Property	-$11,803		-$10,354	-$1,447	-$1	
Broadband Revenue	-$7,235		-$6,347	-$887	-$1	
Interest Income	-$89		-$78	-$11		
Misc. Non Operating Rev.	-$851		-$747	-$104		
Less: Outside Funding Sources	-$186,074		-$163,237	-$22,818	-$19	
Annual MWh Sales **135,522**						
Mills/kWh	71.76	42.93	20.15	5.55	0.00	3.12

Attachment B

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

Attachment B

Utility Number: # 56	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$1,387,888	$1,387,888				
Generated Power	$586,037	$586,037				
Transmission	$1,320		$1,320			
Distribution	$71,299			$71,299		
Consumer Accounts	$263				$263	
Public Relations & Info	$11,873				$11,873	
Energy Services (Conservation)	$46,696	$46,696				
Administration & General	$63,036	$55,590	$116	$6,264	$1,066	
Tax (franchise)	$24,352					$24,352
Tax (property)	$24,044					$24,044
Capital Budget	$94,009	$82,904	$173	$9,342	$1,590	
less Financing from Reserves	-$38,189	-$33,678	-$70	-$3,795	-$646	
Reserve Funding	$31,767	$28,014	$58	$3,157	$537	
"Spread Net Revenue to Others"	-$48,279	-$42,576	-$89	-$4,798	-$817	
Annual MWh Sales **42,095**						
Mills/kWh	53.60	50.15	0.04	1.94	0.33	1.15

Attachment B

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

Utility Number: # 64
Single industrial customer, rates set through contract. Margin over Wholesale Cost of Power is $5,870/mo. Total Industrial sales in 2004: 401,856 MWh Margin = 0.175

Attachment B

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

Utility Number: # 69	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$1,035,622	$1,035,622				
Transmission	$712		$712			
Distribution	$59,107			$59,107		
Customer Service, Accounts & Sales						
Supervision	$12				$12	
Meter Reading	$18			$18		
Customer Records Collection	$54			$54		
Uncollectable Accounts	$4				$4	
Misc. Customer Accounts	$12				$12	
Customer Communication & Education	$9				$9	
Customer Assistance	$49				$49	
Advertising	$1				$1	
Administrative & General	$41,855		$497	$41,297	$61	
Total Interest/Debt Service Expense	$46,721		$556	$46,165		
Capital Projects Funded from Rates						
Production						
Transmission	$67,619		$67,619			
General	$18,698		$222	$18,476		
Other (Increases in inventory)	$2,281		$27	$2,254		
Taxes						
State Utility Tax	$45,972					
FICA	$3,966		$47	$3,913	$6	
State Privelege Tax	$24,261					
Other Taxes	$652					
Incomes:						
Other Contributions						
Construction Fund Transfer	-$36,498		-$434	-$36,064		
Other Fund Transfers	-$7,756		-$92	-$7,653	-$11	
Other Contributions	-$19,618		-$233	-$19,357	-$28	$423,071
Other Revenues	-$2,655		-$32	-$2,620	-$4	
BPA C&R Credit	-$14,355	-$14,355				
Conservation Augmentation Reimbursement	-$14,221	-$14,221				
Annual MWh Sales **29,115**						
Mills/kWh	43.02	34.59	2.37	3.63	0.00	2.44

Attachment B

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

Attachment B

Utility Number: # 86	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Power	$1,758,827	$1,758,827				
Transmission	$257,503		$257,503			
Distribution	$87,087			$87,087	$12	
Customer Service, Accounts & Sales						
Supervision	$320				$320	
Meter Reading	$3,151			$3,151		
Customer Service	$4,064				$4,064	
Cashiering	$2,405				$2,405	
Cash: over/short	$1				$1	
Customer Accounts	$29,000			$29,000		
Delinquency Reporting	$760				$760	
Mail - PUD	$129				$129	
Billing	$724				$724	
Product & Service						
Substn. Maint. & Repair Service Exp.	$253			$ 253		
Mail Service Exp.	$428	$ -	$ 286	$ 133	$ 9	
Mail Service Postage	$3,258	$ -	$ 2,178	$ 1,009	$ 71	
Total Non-Operating Expense	$3,939					
Public Purpose - Supervision	$520				$ 520	
Administrative & General Expense	$101,505	$ -	$ 67,865	$ 31,425	$ 2,215	
Debt Service						
Distribution	$609			$ 609		
General Plant	$356			$ 356		
4/5 Settlement (will check out)	$124,423	$ -	$ 85,043	$ 39,380		
Generation Plant	$2,225	$ 2,225				
Substations	$487			$ 487		
Taxes	$170,130					$ 170,130
Rate-Financed Capital Expenditures						
Generation	$197	$ 197				
Distribution	$22,010			$22,010		
General Plant	$21,383			$ 21,383		
Capitalized Interest and A&G	$1,532	$ -	$ 1,024	$ 474	$ 33	
Annual MWh Sales **75,724**						
Mills/kWh	34.24	23.26	5.47	3.13	0.15	2.25

Utility Number: # 87

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

Total energy sold Customer 1 39,018 MWh
Margin = $5.04/MWh

Total energy sold Customer 2 20,053 MWh
Margin = $4.49/Mh

Utility Number: # 93	
Four industrial customers are sold power under special contracts. Each is charged a different margin.	
Total energy sold Customer 1	110,588 MWh
Margin = $5.00/MWh	
Total energy sold Customer 2	202,967 MWh
Margin = $2.18/Mh	
Total energy sold Customer 3	2,173,245 MWh
Margin = $0.41/MWh	
Total energy sold Customer 4	623,470 MWh
Margin = $0.56/Mh	

Attachment B

Utility Number: # 97	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$7,193,153	$7,193,153				
Transmission	$538,019		$538,019			
Distribution	$332,877			$332,877		
Customer Accounts	$5,427				$5,427	
Customer Service	$527				$527	
Administrative and General	$360,927		$221,458	$137,018	$2,451	
Depreciation and Amortization						
Generation	$658	$658				
Transmission	$57,079		$57,079			
Distribution	$274,219			$274,219		
General	$42,588		$26,310	$16,278		
Amortization	$38,239		$23,623	$14,616		
Tax Expense						
Property	$9,656					$9,656
US Unemployment, FICA, State Unemployment, Workers Comp	$30,715		$18,846	$11,660	$209	
Gross Revenue Tax	$160,277					$160,277
Interest Expense						
Long Term Debt	$437,998		$270,585	$167,413		
Non Operating Margin	-$15,610		-$9,578	-$5,926	-$106	
Miscellaneous Revenues	-$102,599		-$62,953	-$38,950	-$697	
Annual MWh Sales **176,302**						
Mills/kWh	53.11	40.80	6.15	5.16	0.04	0.96

Utility Number: # 99
Three large industrial customers are sold power under a special tariff schedule. Each customer is charged a margin of $387/month. Total annual MWh sales = 283,411 MWh. Margin = $0.049/Mh

Attachment B

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

Utility Number: # 103(b)
Two large industrial customers are sold power under special contracts. Each customer is charged a margin of $100,000. Total annual MWh sales = 349,201 MWh. Margin = $0.57/Mh

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

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

Attachment B

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

Attachment B

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

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

APPENDIX B

VALUE OF DSI SUPPLEMENTAL CONTINGENCY RESERVES

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VALUE OF DSI SUPPLEMENTAL CONTINGENCY RESERVES

Section 7(c)(3) of the Northwest Power Act provides that the Administrator shall adjust rates to the DSI customers "to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers." The DSIs may provide two types of reserves: Supplemental Contingency Reserves and Stability Reserves. The BPA PBL's construct for procuring Supplemental Contingency Reserves (Supplemental Reserves) is described below.

The Northwest Power Pool (NWPP) MORC require BPA, as the control area operator, to carry reserves equal to 5 percent of online hydroelectric generation, 5 percent of online wind generation, and 7 percent of online non-hydroelectric generation. Up to half of this amount may be Supplemental Reserves, and the remainder must be Spinning Reserves responsive to frequency. Supplemental Reserves are defined as both offline generation fully available within 10 minute notice and interruptible load that can be offline within 10 minutes notice.

Supplemental Reserves is an ancillary service that a transmission provider must offer under the FERC pro forma tariff. This ancillary service is made up of both transmission inputs and generation inputs. As the transmission provider, TBL will procure the generation inputs, and may do so from any entity, including PBL, in order to provide this service. However, establishing a mechanism under which PBL may secure Supplemental Reserves from the DSIs does not preclude TBL from purchasing reserves directly from the DSIs.

At this time, PBL does not anticipate needing to purchase any Supplemental Reserves from DSI customers. The BPA FCRPS power system is capable of providing its own Supplemental Contingency Reserves under most circumstances. DSI provided Supplemental Reserves allows BPA to apply more of its generating capacity to serving load, which is especially important during cold snaps, court ordered spill, and other conditions where system flexibility is limited and of greater importance. In such an event that PBL does purchase Supplemental Reserves from a DSI, it will be reflected as an adjustment to the providing customer's IP-07 rate. The level of the credit will be negotiated on an individual customer basis. However, a maximum value that could be reflected in the credit is being proposed. This ceiling is $6.96 kW-month derived from an embedded cost methodology. The details of how this rate was developed can be found in Bermejo *et al*., WP-07-E-BPA-20.

PBL will require any Supplemental Reserves purchased from the DSIs to meet NERC, WECC, and NWPP criteria:

- The time delay between request for load to be interrupted and the agreed amount of DSI load to go offline, is less than or equal to 5 minutes.

- Once there is system disturbance, the interruptible load must be accessible prior to a request for reserves from other NWPP parties.

- The interruptible load is available to be offline for up to 60 minutes.

In addition to these required characteristics, the additional criteria identified below define when PBL may pay up to the maximum value for Supplemental Reserves. Once the required criteria are met the rate paid to a DSI will be negotiated on an individual customer basis, based on the following criteria:

- The extent to which BPA has discretion regarding when and how to use the product in satisfaction of obligations and in response to a qualifying system disturbance.

- Limitations on the number of times or total minutes the product can be utilized.

Pursuant to satisfying the above criteria BPA will satisfy its obligation to provide a reserves credit to the DSI through TBL's Transmission Contracts and the Stability Reserves Credit.

APPENDIX C

MARKET POWER ANALYSIS

GENERATION MARKET POWER ANALYSIS
FOR
BONNEVILLE POWER ADMINISTRATION
POWER BUSINESS LINE

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Summary and Conclusions

This report presents an assessment of Bonneville Power Administration's Power Business Line's (referred to as PBL in this report) ability to exert horizontal market power in its regional markets based on two market power screens adopted by the Federal Energy Regulatory Commission (FERC) in recent orders.[1] The two market power screens are the Pivotal Supplier screen and the Market Share screen. The Pivotal Supplier screen addresses whether the applicant can exercise market power unilaterally based on the ability of other suppliers to meet market demand. An applicant passes the Pivotal Supplier screen if wholesale sales during the peak month can be met without the applicant's uncommitted supplies. The Market Share screen addresses whether the applicant has a dominant position in the market based on its share of uncommitted supplies in the market during each of the four seasons. An applicant passes the Market Share screen if its share of uncommitted capacity is less than 20 percent.

The analyses use historical data for the 2003 calendar year, and examine two relevant regional markets.[2] The first is the BPA Transmission Business Line's (TBL) control area (BPA Control Area or BPAT) and its first-tier markets consisting of 16 connected control areas. The second market is the larger Pacific Northwest (PNW) region and its first-tier markets consisting of 3 connected control areas.[3]

The results of the analyses clearly show that PBL passes the two market power screens in both the BPA Control Area and the PNW. In terms of the Pivotal Supplier screen, our analysis indicates that PBL's dependable supplies are fairly well balanced with its firm long-term sales obligations during peak periods in 2003. In fact, PBL would be short 730 MW if it had to meet its total contract capacity obligations during the peak period of the year. While this result may appear to be counterintuitive, it is consistent with PBL's analysis of its loads and resources as reported in its recent "2003 Pacific Northwest Loads and Resources Study."[4] The study shows that PBL expects to be a net deficit supplier during the peak winter period assuming minimal hydro conditions and average loads. Adjusting for average hydro conditions and peak load conditions results in a similar

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[1] Although FERC has adopted the screens, it continues to refer to them as "interim" screens in light of the fact that FERC's rulemaking proceeding on market based rates (Docket No. RM04-7-00) is ongoing. As recently as February 27-28, 2005, FERC held a Technical Conference to consider, among other things, whether "the interim generation market power screens and approach to mitigation [should] be retained? If not, how should they be revised, or what should replace them?" Docket No. RM04-7-00, "Supplemental Notice of Agenda for Technical Conference," Attach. at 1 (Issued January 21, 2005). Thus, while FERC is actively implementing the two screens -in their present design- to assess utilities' generation market power, there is a possibility that FERC may modify the design of the screens or abandon them altogether. Accordingly, the analysis contained in this report implements the screens in their present design, as of the date of this document.

[2] FERC requires that applicants use unadjusted historical data for the most recent 12-month period in developing the market screens.

[3] For purposes of this analysis, the PNW is defined as the U.S. systems of the Northwest Power Pool (NWPP). See Appendix A for a list of control areas within the NWPP.

[4] Exhibit 2 of the report shows that BPA expects a deficit in its firm loads and resource balance during January and February of 2005 the peak load period in the BPA control area. The study is based on a minimal hydro availability (1937 Water Year) but the deficit is also based on average load levels. Additional hydro generation under normal year hydro conditions would be offset by an increase in PBL's load. Exhibit 5 of the report shows that there would also be a deficit of capacity during the months of January, February and April of 2005. Furthermore, BPA has had energy deficits during February in sixteen of the 50 years from 1929 to 1978 as shown in Exhibit 8 of the report.

supply shortfall. Independent of PBL's supply shortfall, Other Suppliers both within the BPA control area and in the larger PNW have significant amounts of uncommitted supplies, which allow them to satisfy the market's wholesale loads without reliance on PBL supplies. As a result, PBL passes the Pivotal Supplier screen in both regional market areas very easily.

In terms of the Market Share screen analysis, PBL's supply/demand balance leaves it with very limited uncommitted capacity relative to Other Suppliers during each of the four seasons of the year. In the BPA control area market, PBL's market share of the uncommitted capacity does not exceed 21 percent if one ignores the ability to import additional supplies into the market. Taking into account the ability of Other Suppliers to (1) import up to 6,500 MW of additional supplies into the BPA control area, and (2) redirect PBL's exports to customers in the control area,[5] PBL's market share of potential uncommitted supplies is, at the most, 9 percent in the Spring season, 7 percent during the Winter and Summer seasons, and 1 percent in the Fall season. PBL would still be able to pass the market share screen in all four season if Other Suppliers could only import up to 150 MW into the BPA control area each season. In the PNW market, PBL's market share of the market's uncommitted capacity does not exceed 15 percent even if imports are ignored. Therefore, PBL passes the Market Share screen in the PNW market without reliance on imports of additional supplies. Taking into consideration Other Suppliers' ability to import up to 6,500 MW of additional supplies into the PNW market and redirect up to 2,000 MW of exports, PBL's market share reduces to 7 percent in the Winter and Summer seasons, 6 percent in the Spring season and less than 1 percent in the Fall season.

Based on the results of these two Market Screen analyses, there should be the strong presumption that PBL does not possess market power. Instead of being a Pivotal Supplier, our market screen analyses show that PBL's dependable supply is fairly well matched to its long-term sales obligations during peak periods. It does not have any significant uncommitted long-term supplies with which to exert market power in the wholesale market during peak periods. PBL's ability to exert market power, either alone or in conjunction with other suppliers, also appears to be minimal, based on the result of the Market Share analysis. Given very reasonable assumptions about the BPA control area simultaneous transfer capability supported by TBL's studies, PBL's market share never exceeds 9 percent in any season in either the BPA control area or the PNW markets. PBL also passes the Market Share screens in the PNW market if imports are ignored, and in the BPA control area market if its transmission import capability exceeds 150 MW.

Section II of this report summarizes the FERC orders regarding the two Market Screens and presents an overview of the methodology used to arrive at our conclusions. Background information on BPA and its operations is presented in Section III. A study of the relevant geographic markets and first-tier control areas is summarized in Section IV. A more detailed market analysis of BPA control area, with all relevant data is presented in Section V. Section VI presents a detailed analysis of the PNW market, with all relevant data. Section VII presents our conclusions.

[5]The amount of imports by Other (non-PBL) Suppliers will depend on the amount of uncommitted capacity in adjacent control areas less the amount of transmission capacity allocated to PBL's long-term imports. In addition to increasing imports Other Suppliers who are scheduled to receive PBL's exports can reschedule those exports to customers in the control area, thereby increasing the amount of competitive supplies in the control area.

Methodology Overview and FERC Orders

In its "Order on rehearing and modifying interim generation market power analysis and mitigation policy,"[6] FERC adopted two new interim Market Power (MP) screens. The first is a Pivotal Supplier screen, which measures market power at peak times, particularly in spot markets. The presumption is that if the total demand in the market area can only be met with the applicant contributing some or all of its uncommitted supplies, then the applicant could extract significant monopoly rents during peak periods. The second is a Market Share screen that measures whether the applicant has a dominant position in the market based on its share of total uncommitted supplies for each of the four seasons. Market Share is an indicator of whether the applicant has unilateral market power and may indicate the presence of the ability to facilitate coordinated interaction with other suppliers. FERC describes the two screens as "indicative" because, if an applicant passes both screens, the presumption is that it does not have the ability to exercise market power either unilaterally or in coordinated interaction with other suppliers. If an applicant fails either screen, there is a presumption that it has market power. In either case the applicant or intervenors can provide evidence to disprove the presumption.

The Pivotal Supplier analysis is based on first calculating the uncommitted supplies of both the applicant and other suppliers available to compete for the wholesale load in the relevant market. This is a measure of supplies in the market not committed to meet firm long-term obligations such as utilities' native loads and long-term sales. Uncommitted supply is the difference between net supplies available and load obligations. Net supplies available equals the total nameplate capacity of generation owned or controlled through contracts and firm purchases, less operating reserves, and other capacity adjustments. Load obligations are the sum of native load commitments and long-term firm sales. The capacity available for wholesale sales is calculated by adding the total uncommitted capacity of the applicant and other suppliers within the market area to the capacity of potential imports from first tier markets (i.e., markets that are directly connected to the applicant's market area). The net uncommitted supply is then calculated as the capacity available for wholesale sales less the wholesale load. The wholesale load is estimated as the annual system peak load less the proxy for the native load obligation (i.e., the average of the daily native load peaks, excluding weekend days and holidays, during the month in which the annual peak load occurs). If the applicant's uncommitted capacity is less than the net uncommitted market supply, then the applicant passes the Pivotal Supplier screen.

The Market Share analysis also requires the calculation of the applicant and other suppliers' uncommitted capacity with some variations. The calculation is done for each of the four seasons, and the proxy native load is defined as the minimum peak day load for each season considered. Suppliers are also adjusted for any seasonal variations such as planned outages and long-term contract commitments.[7] The applicant's market share is then calculated based on its uncommitted capacity as a percent of the total uncommitted capacity available to serve the wholesale market. If the applicant's market share is less than 20 percent in each of the four seasons, then it passes the Market Share screen.

If an applicant is found to have market power, the applicant can: (1) propose a more robust market power study, referred to as the Delivered Price Test (DPT); (2) file a mitigation proposal tailored to its particular circumstances that would eliminate the ability to exercise market power; and/or (3) inform the Commission that it will adopt FERC's default cost-based rates or propose other cost-

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[6] "Order on rehearing and modifying interim generation market power analysis and mitigation policy" (Issued April 14, 2004) 107 FERC ¶ 61, 018. [FERC's April 14, 2004 Order.]

[7] Planned outages are assumed to be zero in the Pivotal Supplier analysis.

based rates and submit cost support for such rates. Before the Commission considers the DPT, the applicant must be found to have "failed" one of the two "indicative" screens or so concede.

Various parties submitted requests for rehearing of the April 14, 2004 Order. In response, FERC issued "Order on Rehearing," on July 8, 2004.[8] In this order, FERC stood by its interim market power screens adopted in April, but sought to clarify implementation issues regarding the screens and the associated market-based rates process.[9]

The FERC Orders provide general guidance on the method and calculations for the market power screens analyses. FERC specifically allows applicants to make simplifying assumptions. For example, FERC states: "…. any applicant, regardless of size, has the option of making simplifying assumptions in its analysis where appropriate. Appropriate simplifying assumptions are those assumptions that do not affect the underlying methodology utilized by these screens."[10] In another section of its Order, FERC reminds applicants "…they may make appropriate simplifying assumptions that do not affect the underlying methodologies utilized by the generation market power screens."[11] Accordingly, when necessary or appropriate, the analysis contained herein incorporates simplifying assumptions. When there were choices for assumptions, conservative assumptions (i.e., assumptions likely to increase PBL's uncommitted capacity or market share) were made.

background information on bpa

BPA is a federal agency under the U.S. Department of Energy, established in 1937. BPA is the designated marketing agency for 31 Federal hydroelectric projects and some non-federal projects located in the PNW. BPA primary service area is the PNW comprised of Oregon, Washington, Idaho, western Montana and portions of California, Nevada, Utah and Wyoming. BPA sales account for approximately 45 percent of the electric power consumed in the PNW.[12] BPA also sells power that is surplus to the needs of its customers in the wholesale market to parties in the PNW, Canada and the Pacific Southwest, but primarily to parties located in California. BPA is a self-funding agency, which pays for its costs through sales of power and transmission services. Both power and transmission services are sold to its customers at cost.

On October 1, 1996, BPA separated its marketing function from its transmission function in order to avoid potential conflict of interest problems in the competitive bulk power market. BPA reorganized into four main groups: the PBL, the Transmission Business Line (TBL), the Energy Efficiency Group, and Corporate. On February 28, 1999, the Energy Efficiency Group became a part of the PBL. The PBL markets wholesale power primarily to public utilities in the Northwest, which in turn retail the power to farms, businesses and homes. Some investor owned utilities (IOUs) also buy power from the PBL. In addition, the PBL has historically sold power directly to up to 15 large PNW industrial plants, referred to as Direct Service Industries, ("DSIs"), many of

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[8] "Order on Rehearing" (Issued July 8, 2004) 108 FERC ¶ 61, 026. [FERC's July 8, 2004 Order.]

[9] FERC also issued an order "Order Implementing New Generation Market Power Analysis and Mitigation Procedures," dated May 13, 2004. In this order, the Commission addresses the procedures for implementing the new interim generation market power analysis and mitigation policy announced in the Commission's April 14, 2004 Order.

[10] FERC's April 14, 2004 Order, ¶ 117.

[11] FERC's April 14, 2004 Order, Footnote 185.

[12] BPA Facts, April 2004; Available on BPA website.

them aluminum smelters. However, during 2003 most of these plants were not operating or operating at reduced capacity.

BPA owns and TBL operates about three-quarters of the PNW's high-voltage electric grid. TBL provides open, non-discriminatory transmission services at competitive rates. Its 15,000 miles of power lines carry power from the dams and other power plants to customers of PBL and those of other suppliers for delivery throughout the PNW. TBL also has transmission links with other regions, allowing for imports and exports of power into the PNW.

BPA Generating Resources and Firm Purchase Contracts

PBL markets power generated at Federal Columbia River Power System (FCRPS) projects on the Columbia and Snake rivers. The FCRPS projects consist of 10 projects owned by the U.S. Bureau of Reclamation and 21 projects owned by the U.S. Corps of Engineers. PBL also markets the generation from seven small hydro projects owned by the City of Idaho Falls, Lewis County Public Utility District and other entities. The combined nameplate generating capacity of these hydro projects is 20,568 MW including pumped storage and non-federal hydro resources controlled by BPA.[13] In addition, PBL markets the generation from the 1,200 MW Columbia Generating Station (formerly known as WNP-2), a nuclear power plant operated by Energy Northwest, Inc.[14] Lastly, PBL markets the output from several renewable power plants, primarily cogeneration and wind turbines, under power purchase contracts with PBL. The total nameplate generating capacity available to be marketed by PBL is 22,051 MW.

In terms of rated capacities, PBL is potentially the largest marketer of electric energy supplies in the Western Electric Coordination Council (WECC) region. In addition to the generating resources under its control, PBL also had long-term power purchase contracts with 15 suppliers within the PNW of approximately 1,400 MW of capacity each month during 2003. PBL also had long-term power purchase contracts with 12 parties outside the PNW of approximately 250 MW of capacity on average each month. Adding these additional resources to PBL generating capacity would imply that PBL had approximately 24,000 MW of capacity to market during 2003. However, there are a number of factors that limit BPA ability to control the amount of energy produced by its extensive hydroelectric system.

Hydroelectric Resource Limitations

There are a number of factors that restrict how the BPA system is operated in the production of electricity. Nine of the hydroelectric projects are referred to as "run-of-the river," because they have minimal, if any, storage capacity. These nine projects have a total nameplate capacity of 11,532 MW or 56 percent of the total hydroelectric system.[15] Most of the run-of-the-river projects are downstream of large storage projects, which allow BPA some flexibility in shifting generation between periods. However, once water is released from a headwaters storage project, such as

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[13] The capacity rating of these projects was obtained from the WECC's power plant database provided in electronic form which is consistent with the December 2003 Pacific Northwest Loads and Resources Study published by BPA indicated a 20,510 MW rating for these projects due to a 56 MW derating of Cowlitz Falls hydro facilities as a result of operational restrictions in January. See White Book pg. 19-20.

[14] The BPA 2003 White Book had a 1,150 MW capacity rating for the Columbia Generating Station but to be conservative we used the name plate rating contained in the WECC database.

[15] The nine projects are Chief Joseph, Lower Granite, Little Goose, Lower Monumental, Ice Harbor, McNary, John Day, The Dalles and Bonneville. See Columbia River System Operating Review, Final Environmental Impact Statement; Appendix I Sec. 2.2.3, Issued 11/95.

Dworshak, it's only a matter of hours before that water appears at the run-of-the-river projects on the Lower Snake River. With no storage capability on the Lower Snake River projects, the water is either used to generate electricity or it must be spilled. This means that if BPA decides to generate electricity during a specific hour from its up stream dams (with storage capacity) to take advantage of market prices, it will be forced to sell generation a few hours later from dams downstream no matter what the price.

Another factor that limits BPA flexibility is the number of non-federally owned projects downstream of the large federal projects such as Grand Coulee. These downstream projects are owned and operated by public utility districts ("PUDs") in the area. Since the operation of the federal projects will affect the operations of the PUD projects, BPA is forced to plan and coordinate the operation of its projects with these PUDs. Therefore, BPA ability to operate its system is significantly more restricted than the owners of non-hydroelectric resources.

A third factor that limits BPA flexibility is the fish flow requirements imposed by the National Oceanic and Atmospheric Administration (NOAA) FCRPS Biological Opinions. BPA and the other Federal agencies responsible for managing and operating the FCRPS are statutorily required to do so in a manner that provides "equitable treatment" for fish and wildlife alongside other purposes (such as power generation) for which the FCRPS is operated.[16] In 1995, the National Marine Fisheries Service (NMFS) (now NOAA), issued the Biological Opinion that changed the focus of the operation of the FCRPS for fish passage to seasonal flow-based targets from storage-based targets.[17] This change emphasizes the maintenance of monthly flows at hydroelectric projects, thereby limiting the ability of the system to shift and shape flows to meet generation objectives. The opinion specifies dates for achieving storage levels at the system's reservoirs and specifies the amount of water that has to be released for fish each season. The NMFS opinion noted that these requirements increase the priority for the use of reservoirs for fish flow augmentation relative to power production. On December 21, 2000, NOAA Fisheries issued a new Biological Opinion, which provided revised flow objectives that decreased rather than increased BPA flexibility in generating power from the FCRPS.[18]

In addition to having limited flexibility in the operation of its hydroelectric facilities, the productive capability of BPA facilities is also limited by the availability of water. For conventional fossil-based and nuclear generating facilities, their productive capacity is rarely, if ever, limited by fuel availability. This is not true for hydroelectric projects. As a result, the capacity rating (or instantaneous generating capacity) of a hydroelectric facility is not predictive of its productive capability in the same way that the nameplate capacity rating is for a fossil or nuclear facility.

PBL's Customers, Load Obligations and Power Sales Contracts

PBL has system sales and load obligations to federal agencies, the U.S. Bureau of Reclamation (USBR), public agencies, cooperatives, IOUs, and DSI customers within the PNW. Some of PBL's customers have other sources of generating supplies, through ownership, control or purchase contracts, and rely on PBL for only a portion of their requirements. PBL also has contracts with power marketing companies and sells or exchanges power with entities in other parts of the western U.S. and in Canada.

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[16] 16 U.S.C. 16 U.S.C.§ 839b(h)(11)(A).

[17] Biological Opinion Endangered Species Act, Section 7, Consultation by National Marine Fisheries Services Northwest Region, issued March 1995.

[18] NOAA Fisheries; "2000 Federal Columbia River Power System Biological Opinion," dated December 21, 2000.

Rate Schedules

PBL sells power to customers under five rate schedules using several types of power sales contracts (PSCs). Most of the rate schedules are restricted to specific customer groups and certain sales products.

Priority Firm Power Rate (PF-02) – is available for the purchase of firm power by customers in the PNW who belong to the following groups: public bodies, cooperatives, and Federal agencies. Power can be purchased through four basic contract types: full service, partial service, block and Slice. For non-Slice customers, the rate schedule has a monthly demand charge that is applied to the purchaser's measured demand as specified in the contract. There is also an energy charge that has two rates, one for heavy load hours (HLH) and one for light load hours (LLH), which are applied to the purchaser's entitlements during those hours as specified by the contract. The rates in the schedule are in effect beginning October 1, 2001, and are available for purchases under five-year contract with initial rates fixed for a three- or five-year period. The Slice product is priced differently than other PF products (see Section 2 below).

Residential Load Firm Power Rate (RL-02) – is available for purchases of firm power by customers in the PNW who are IOUs under net requirements contracts. Only the block contract is available under this rate schedule and the contract rates are only available under contracts for five years. The rate schedules are identical to the rates under the five-year priority firm power contract.

New Resource Firm Power Rate (NR-02) – is available for purchases of firm power by customers within the PNW who are IOUs under net requirements contracts and any public body, cooperative or Federal agency which needs power to serve any New Large Single Load (NLSL). Contracts have a five-year term starting in October 2001, with an initial fixed rate schedule available for a term of three or five years. All the basic sales contracts, except Slice, are available under the same five-year term with the same two initial fixed rate schedules.

Industrial Firm Power Rate (IP-02) – is available for purchases of firm power by BPA DSI customers for use in their industrial operations. Customers are eligible to purchase under this rate schedule for five years. Only the firm take-or-pay block contract is available under this rate schedule. The demand charge is the same as the PF rate schedule but the energy charge rates are higher.

Non-Firm Energy Rate (NF-02) – is available for the purchase of non-firm energy to be used both inside and outside the United States, including sales under the Western Systems Power Pool (WSPP) agreements and sales to consumers. The offer of non-firm energy under this schedule is determined by BPA. There are four types of rates for non-firm energy: standard, market expansion, incremental and contract. This rate will not be offered in the next rate period.

Firm Power Products and Services Rate (FPS-96R) – is available for the purchase of firm power, capacity without energy, supplemental control area services, shaping services and reservation and rights to change services for use inside and outside the Pacific Northwest. BPA is not obligated to enter into agreements to sell products and services under this rate schedule. While there is a posted rate, the actual rate may be higher or lower as mutually agreed by BPA and the purchaser.

Customer Products

Two of PBL's most significant products are its Full Service and Partial Service contracts. Full Service is available to customers who either have no resources or whose resources meet the criteria for small, non-dispatchable resources. Partial Service is available to purchasers who have contractual arrangements or generating resources with firm capabilities and therefore require a product other than Full Service to meet their power deficit. PBL had over 100 Full and Partial Service customers in 2003 with a combined peak period load of 6,558 MW.[19]

Another type of PBL product is a Block contract, which requires that a customer receives and purchases a contract-specified block of energy for every hour of the contract period (i.e., 100 percent load factor during HLH and/or LLH periods for the month). This product is available in HLH and LLH quantities per month with the hourly amount flat for all hours in such periods. There are two variations of the standard Block product, block product with Factoring and Block product with Shaping Capacity. Block product with Factoring provides the service of distributing the customer's Block energy to follow their hourly load up to the amount of energy specified by the contract. The Block product with Shaping Capacity allows the customer to pre-schedule Block energy with some limited shaping during HLH within a contractually specified bandwidth. In 2003, PBL had three customers with a Block contract under the PF-02 rate schedule. Their combined peak period load was 1,256 MW. PBL also had six DSI customers with Block contracts under the IP-02 rate schedule, however their load was approximately 570 MW during 2003 peak period.

Slice contracts are only available to public "preference" customers[20] who must purchase the Slice product combined with the purchase of the Slice Block product. The Slice Block product is similar to the Block product discussed above with a 10-year term. The Slice product differs from a traditional power sales contract in that power is made available based on the level and shape of the generation output of a set of specific Federal resources less certain Federal obligations (usually referred to as the Federal System Slice Resource Stack). These specific Federal resources include the outputs of hydroelectric projects and other resources listed in Appendix B, as well as power deliveries from the Non-Federal Canadian Entitlement Return ("CER") for the Columbia Storage Power Exchange ("CSPE"). The Federal contract obligations that are subtracted from the Federal resources include deliveries for the CER to Canada and Federal pumping loads. PBL is obligated to provide the contract specified percentage of the Federal System Slice Resource Stack to the Slice customers to meet their own load obligations or sales to third parties. The Slice product is only provided under the Priority Firm Power Rate Schedule with a fixed rate over the Fiscal Year (FY) 2002 through the FY 2006 period. The fixed monthly rate is $1,419,430 per 1 percent of the Federal System Slice Resource Stack. PBL has 25 Slice customers whose combined Slice requirements equal 22.63 percent of the Federal System Slice Resource Stack. The amount of Slice product available for delivery is dependent on the Federal system operating decisions, and hydro production, which varies by water conditions, and generation from non-hydro Federal resources.

In addition to the products just described, which are primarily (and in some cases exclusively) offered to preference customers in the PNW, PBL also sells power to IOUs, marketers and others both inside the PNW and outside the region under long-term contracts. In 2003, PBL had intra-regional long-term sales contracts with 9 customers with an average monthly capacity obligation of 1,270 MW. The six largest contracts accounted for essentially all of the capacity.[21]

During 2003, PBL also had long-term export contracts with 18 entities. Eight of these customers are public agencies in California with the others being cooperatives and power marketers. The contract terms vary from one year for two of the power marketers to 20 years for a number of the

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[19] Based on metered customers' hourly load information provided by PBL, which excluded Slice Customers' loads and segmented remaining loads depending on their location inside (5,132 MW peak) and outside (1,303 MW peak) the BPA control area (see Table VI).

[20] Public entities and cooperatives are BPA "preference" customers, which means they are statutorily granted preference and priority to the power that BPA markets. 16 U.S.C. §§ 839c(a), 832c(a).

[21] Intra-regional contracts refer to contracts for supplies and deliveries within the PNW.

public agencies. The capacity load associated with the exports varied from month to month in 2003, averaging approximately 791 MW. A number of these contracts are exchange agreements where PBL provides capacity and energy during peak periods and the buyer returns the energy during off-peak periods and provides a financial payment. These contracts allow PBL to conserve its hydro generation to be used during peak periods when the energy value is at a premium.
PBL also buys and sells power under short-term contracts to several parties within the PNW and outside the region, principally in California. In 2003, PBL entered into hundreds of forward and spot power sales contracts with terms varying from a day to several months. The spring and summer seasons were the highest sales periods with average monthly capacity sales of approximately 2,300 MW. Sales during the winter and fall seasons were half as large, averaging approximately 1,200 MW monthly. PBL had much fewer power purchase contracts for a lot less capacity during 2003. Capacity purchases average 400 MW during the winter and spring seasons, 560 MW during the summer season and 140 MW during the fall season.

Canadian Entitlement Return

The Columbia River Treaty between the United States and Canada enhanced the use of storage in the Columbia River Basin with the construction of three large storage projects in Canada. These Canadian Treaty projects provide downstream power benefits that are shared equally between the U.S. and Canada. PBL and the non-Federal mid-Columbia participants are obligated to return their share of the downstream power benefits owed to Canada. This is called the Canadian Entitlement Return (CER) to Canada. The non-Federal Canadian Entitlement obligations are delivered to PBL, which delivers both PBL's and the non-federal participants' obligations to Canada. The non-Federal entities' Canadian Entitlement obligation is included in each participating utility's load and resource balance as a delivery to PBL. During 2003, PBL's average monthly capacity obligation under the CER was 1,041 MW.

BPA Transmission System

TBL operates over 15,000 circuit miles of electric transmission lines and markets transmission services on a non-discriminatory basis to all customers in the PNW. TBL's service area includes Oregon, Washington, Idaho, western Montana and small portions of Wyoming, Nevada, Utah, California and eastern Montana. TBL's transmission lines connect to Canada, California, inland southwest and eastern Montana. BPA transmission grid provides approximately 75 percent of the PNW's high voltage transmission capacity.
There are five major paths into the BPA control area from neighboring control areas to the north, east and south. They include: (1) the Northern Intertie (NI) connecting BC Hydro, (2) the Pacific DC Intertie (PDCI) connecting Southern California, (3) the California-Oregon Intertie (COI) connecting Northern California, (4) a collection of lines to Montana, and (5) a collection of lines to Idaho. Each of these paths has been assigned a maximum transfer capability that indicates the maximum power the path can support. Based on information from BPA and a 2003 WECC report, the ratings of the paths were: 3,150 MW for the NI North to South (N-S); 3,100 MW for the PDCI S-N; 3,675 MW for the COI S-N; 2,200 MW for the Montana path E-W; and 2,400 MW for the Idaho path E-W.[22] These are the non-simultaneous ratings. Simultaneous ratings come into play

[22] Information for the COI, PDCI and NI paths was contained in the Standing Order No. 330 issued by BPA on October 30, 1998. Additional information for the COI, PDCI and NI paths is available in Attachment 2 of a report titled "1998-99 Winter Operational Transfer Capability of the California-Oregon Intertie and the Pacific DC Intertie (South to North) & Northwest Import Capability," submitted to Northwest Operational-Planning Study Group,

when there is interaction between two paths. Where there is interaction, there is some constraint that prevents both paths from being used at their respective maximum (non-simultaneous) ratings. Typically the relationship between two or more paths is represented in the form of a "nomogram." Because of the complex nature of BPA transmission system, TBL developed a simultaneous relationship between the three eastern paths, NI, PDCI and COI, while assuming specific load conditions on the two eastern paths.[23] That relationship was presented in System Dispatcher Standing Order No. 330, issued on October 30, 1998. A copy of the nomogram issued is shown in Figure 3. Based on the nomogram, the BPA system could simultaneously import 1,000 MW on the NI, 3,100 MW on the PDCI and 3,675 MW on the COI for a total of 7,775 MW. The rating of the PDCI transmission path was reduced recently due to the loss of large aluminum smelter loads in the PNW, which acted as a buffer in case there was a loss of power on the path.

Relevant Geographic Markets and First Tier Control Areas

Regional Reliability Councils and Control Areas

The North American Electric Reliability Council (NERC) has ten regional councils, shown in Figure 1. The WECC region comprises all or part of Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington and Wyoming, as well as the Canadian provinces of Alberta and British Columbia, and the northern portion of Baja California Norte, Mexico. One of the four sub-regions of the WECC is the Northwest Power Pool (NWPP). The sub-regions and control areas in the WECC are listed in Appendix A. The NWPP has sixteen control areas, one of which is Bonneville Power Administration Transmission (BPAT) and two of which, Alberta Electric Supply Company, LLC and B. C. Hydro & Power Authority, are in Canada. Figure 2 shows a map of the Control Areas and the Utility District Boundaries in the PNW. Compared to other areas of the country, the Northwest has many control areas.

Discussion of Geographic Markets in FERC's Orders

FERC stated that "default relevant geographic markets under both screens will be first, the control area market where the applicant is physically located, and second, the markets directly interconnected to the applicant's control area market (first-tier markets). In this default analysis, we will consider only those supplies that are located in the market being considered (relevant market) and those in first-tier markets to the relevant market. Supplies being imported from first-tier markets will be limited by simultaneous transmission import capability."[24]

In its clarification, FERC said that, "[f]or purposes of running the indicative screens, the control area includes both the control area market where the applicant is physically located, as well as the control areas directly interconnected to the applicant's control area (first-tier control areas)."[25]

September 18, 1998. Information for the Montana and Idaho paths is contained in the WECC 2005 Path Rating Catalog issued February 2005.

[23] Historical East to West loading on the Montana and Idaho transmission paths have not been very heavy during peak periods, which significantly reduced the probability of the simultaneous loading of these lines with the three other main transmission paths.

[24] FERC's April 14, 2004 Order, ¶ 73.

[25] FERC's July 8, 2004 Order, ¶ 31.

FERC further explained, "we will continue with the determination made in the April 14 Order that the approach of defining the default relevant geographic market as the control area is adequate and allow applicants and intervenors on a case-by-case basis to provide historical data and other evidence to demonstrate that, due to transmission limitations, the relevant market or markets is larger or smaller than the control area."[26]

However, FERC recognizes "that due to the integrated Western resource system, larger regional market definitions may be more appropriate, especially in the Northwest where hydroelectric power is such a critical part of the regional generation portfolio. As such, and consistent with our discussion of geographic areas above, we will allow applicants located in the Western interconnection to provide evidence that a larger geographic market definition than our control-area-by-control area approach is appropriate. Applicants making such arguments should justify their choice of market definition by citing the relevant facts and providing supporting data (i.e., historical sales indicating the actual scope of the market)."[27] But in a footnote to this statement, FERC states that, "[a]lthough we will consider such a showing, we still require that such applicants submit the generation market power screens adopted herein using the default relevant market(s)."[28]

Puget Sound Energy (Puget), an IOU located in the Seattle area, submitted a market based rate filing with FERC, using its control area market as the relevant market in both the Pivotal Supplier and the Market Share analyses.[29] However, Puget reserved the right to show that the broader PNW is the appropriate market for conducting generation market power screens in the future.[30]

In analyzing PBL's potential to exert market power, two relevant geographic markets are considered: (i) BPA control area; and (ii) the PNW region. In the first case, the relevant geographic market is BPA Control Area, which has access to a secondary market consisting of its First Tier Control Areas. In the case on the BPA market the First Tier Control Areas consist of all other Control Areas in the PNW, in addition to the California Independent System Operator (CAISO), Los Angeles Department of Water and Power (LADWP), and B.C. Hydro & Power Authority (BC Hydro). Access to this secondary market is determined by the simultaneous transfer capability between the secondary and the primary markets. In our second case, the relevant geographic markets include the entire PNW as the primary market with the secondary market, consisting of PNW's First Tier Control Areas, which are the CAISO, LADWP, and BC Hydro.

Market Analysis of BPA Control Area

As discussed above, PBL has large load obligations associated with its full service and partial service contracts, Block contracts, Intra-Regional sales contracts and Export contracts. PBL's full and partial service contracts are "load following" contracts with PBL's obligation to these customers very similar to a utility's obligation to its retail load. Therefore, for the purpose of the market power screen analyses, we have assumed the combined load of the DSIs, full service, and

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[26] FERC's July 8, 2004 Order, ¶ 35.

[27] FERC's July 8, 2004 Order, ¶ 127.

[28] FERC's April 14, 2004 Order, Footnote 111.

[29] Market Power Analysis of Puget Sound Energy, Inc., August 11, 2004, Page 3.

[30] Market Power Analysis of Puget Sound Energy, Inc., August 11, 2004, Footnote 3.

partial service customers represents PBL's "native load."[31] PBL's load obligations associated with Block contracts, intra-regional sales and export contracts of one year or more are categorized as firm long-term sales which have specific capacity obligations. PBL's load obligations associated with the Slice resource portion of the Slice contracts are taken into account through an adjustment to PBL's available generating supplies.

FERC requires that "[i]n performing all screens, applicants are required to prepare them as designed, and must use the most recent unadjusted 12 months' historical data as a snapshot in time."[32] Data for this analysis is based on the 2003 calendar year. That is the most recent calendar year for which all the required data are available.

The following section discusses the data used to determine the capacity available for wholesale sales that is required for the analysis of the two screens. This is followed by a discussion of the analysis to determine if PBL passes or fails the Pivotal Supplier screen and the Market Share screen, for each of the four seasons.

Capacity Available for Wholesale Sales

The Capacity Available for Wholesale Sales is equal to Net Supplies Available less Total Load Obligations, for both PBL and Other Suppliers within the control area plus Potential Additional Imports into the control area. Throughout this report "Other Suppliers" refers to BPA Slice customers and entities other than BPA that control generating facilities in BPA control area (or the PNW). Components of Net Supplies Available, Total Load Obligations and Potential Additional Imports are discussed below. These components are explained using the approach for calculating the screens for the BPA Control Area. The calculations for screens for the PNW are similar to those for the BPA control area.

Net Supplies Available

Net supplies available for both PBL and Other Suppliers within the BPA control area are estimated by adjusting the nameplate capacity of their generating supplies for planned outages; de-rating of hydro, wind and solar; operating reserves; and other obligations.

Generating Capacity

Calculations for Capacity Available for Wholesale Sales start with nameplate capacity, with amounts disaggregated by resource type. An extensive database was developed on power plants within the WECC. The primary sources for the data were the WECC and the Pacific Northwest Utilities Conference Committee (PNUCC).[33] Other data sources included PowerDat, the annual Pacific Northwest Loads and Resources Study (BPA White Book) and various other sources through the Internet. The database allowed data to be aggregated by various categories including type of generation (i.e., hydro, nuclear, etc.), ownership, and location by control area. The nameplate capacities by resource types controlled by PBL and Other Suppliers in BPA control area

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[31] In the July 8, 2004 Order, FERC allowed applicants to deduct "load following" and "provider of last resort" contracts loads from their net capacity by using the contractual peak load obligation in the Pivotal Supplier screen analysis and using the seasonal baseline demand levels served under the contract as the adjustment in the Market Share screen analysis. See ¶ 66.

[32] FERC's April 14, 2004 Order, ¶ 118.

[33] Existing Generation and Significant Additions and Changes to System Facilities 2003 – 2013 as of January 1, 2004; Western Electric Coordinating Council, issued July 2004 and PNUCC's Excel workbook "NRF Section III.xls."

are presented in Table I below. The data clearly shows the almost total reliance of the BPA system on hydroelectric supplies.

Table I

Generation Power Plant Capacity in the BPA Control Area (MW)

Power Plants in BPA Control Area	BPA Controlled Power Plants	Partial Req. Customers Power Plants	Other Suppliers Power Plants	Total Power Plants Capacity
Federal Hydro	20,131	-	-	20,131
Non-Federal Hydro	123	95	371	589
Federal Pumped Storage	314	-	-	314
Fossil Fuel - Coal	-	-	1,340	1,340
Fossil Fuel - Other & Misc.	71	6	2,183	2,260
Nuclear	1,200	-	-	1,200
Wind & Solar	174	-	-	174
Geothermal	-	-	-	-
TOTAL	22,013	101	3,894	26,007
Power Plants outside BPA Control Area				
Wind & Solar	33		9	41
Non-Federal Hydro		83	38	121

De-rating of Hydro and Wind

FERC recognized the fact that using the instantaneous or nameplate capacity of hydroelectric facilities can bias the results of the mandated market power screens, and as a result modified its approach. Therefore, FERC permits applicants to de-rate their hydroelectric capacity in conducting the two interim generation market power screens. FERC recommended the following:
Applicants that elect to do this must de-rate their hydroelectric capacity based on historical capacity factors, and they should use a five-year average capacity factor and a sensitivity test using the lowest capacity factor in the previous five years in order to more accurately capture hydroelectric availability.[34] [35]

Five-year average capacity factors for de-rating the Federal hydro system were derived from monthly hydro generation for the period 1999 to 2003. Five-year average capacity factors for hydro, other than the Federal hydro system, were similarly developed (see Table II). PBL provided historical hydro-generation data for the Federal system and data for other suppliers in WECC were obtained from Energy Information Administration's Form 860.

[34] FERC's April 14, 2004 Order, ¶ 126.

[35] Results based on the lowest capacity factor in the previous five years are not presented. PBL passes the market screens based on average hydro conditions and would, even more easily, pass the screens based on the minimum hydro conditions.

Table II

Hydroelectric Power Plants
Average Seasonal C.F. for 1999-2003

Relevant Period	BPA	Other PNW Suppliers
Peak Month	45.1%	48.4%
Winter	44.7%	48.2%
Spring	46.0%	50.1%
Summer	45.7%	45.9%
Fall	34.4%	37.0%

For the Pivotal Supplier screen, capacity factors for de-rating were based on data for the month of February, the month in which the 2003 annual peak occurred for the BPA control area. For the Market Share screens, seasonal capacity factors for each of the four seasons were calculated and used to de-rate the Federal hydro system capacity.

Generation from wind and solar resources is also dependent on weather conditions and these resources are generally assigned zero firm capacity. FERC recognized that wind units are energy limited and allowed applicants to de-rate the available capacity of these units using a five-year average of historical output.[36] Most of the wind resources did not have 5 years of historical output. Therefore, we used the available data on facilities that had more than one year of operation to estimate an annual capacity factor, which was applied to all facilities.[37] The wind resources were de-rated by 70 percent. PBL has 206 MW of nameplate wind capacity, or one percent of its total nameplate capacity. PBL has less than 1 MW of solar capacity under contract and its average available energy was insignificant; therefore, solar capacity was de-rated by 100 percent.

Planned Outages

The Commission does not expect that applicants will have planned generation outages scheduled for the annual peak load day. However, on a case-by-case basis, FERC will consider credible evidence that planned generation outages for the peak load day of the year should be included based on the particular circumstances of the applicant.[38] Planned outages were assumed to be zero for the Pivotal Supplier screen.

For the Market Share screen, the FERC Order notes, "planned outage amounts should be consistent with those as reported in FERC Form No. 714. To determine the amount of planned outages for a given season, divide the total number of MW-days of outages by the total number of days in the season. For example, if 500 MW of generation is out for six days during the winter period the calculation of planned outages would be: (500 MW X 6)/91 or 33 MW."[39]

[36] FERC's July 8, 2004 Order, ¶ 129.

[37] The Pacific Northwest Loads and Resources Study (referred to as the White Book), published annually, is the source of the data on annual megawatts of average capacity available from wind and solar resources. The 2002 White Book and the more recently published 2003 White Book are available at http://www.bpa.gov/power/pgp/whitebook/2002/ and http://www.bpa.gov/power/pgp/whitebook/2003/.

[38] FERC's April 14, 2004, ¶ 97.

[39] FERC's April 14, 2004 Order, ¶ 100.

Table III

Planned Outages (MW)

Resource Type	Winter	Spring	Summer	Fall
Nuclear	-	377	326	-
	Winter % of Capacity	Spring % of Capacity	Summer % of Capacity	Fall % of Capacity
Coal	-	2.28	2.28	1.95
Other Thermal	-	1.44	1.44	1.23

A simplified approach for non-nuclear resources, based on percentages of installed capacity, was used. Planned outages for the Columbia Generating Station nuclear power plant are actual outages for 2003. Planned outages for thermal units are based on percent of time typically required for maintenance of thermal plants (6.5% for coal and 4.1% for other thermal plants and the monthly distribution of outage days of other power plants in the PNW. The data on percent of time are from the Energy Information Administration ("EIA").[40] The monthly distribution of outage days is based on data for several other control areas in the PNW, as reported in FERC Form 714 for the year 2003.[41] The monthly distribution was adjusted so that planned outages in the Winter season were zero. The results for the BPA control area are shown in Table III.

Planned outages are implicitly incorporated into the de-rating of hydro and wind resources. Therefore, there is no additional planned outage reduction of the hydro resources. Planned outages reduce the non-hydro supplies available during the Spring, Summer and Fall seasons.

Operating Reserves

FERC allows the State or Regional Reliability Council operating reserve requirements to be used as the default measure for the amount of capacity a supplier must keep in reserve in case of emergencies.[42] In both market screens, we used the operating reserve requirements specified by the NWPP to reduce the available operating capacity a supplier has available to sell to the wholesale market. NWPP requires operating reserves of 5 percent for hydro and wind power plants and 7 percent for thermal plants.[43] Operating reserves are required for all loads, including any potential wholesale spot sales.

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40 Private communication with EIA, September 27, 2004.

41 FERC Form 714 data were available for Chelan County PUD, Grant County PUD, Idaho Power Company, Northwestern Energy, Pacificorp, Portland General Electric Company,, Seattle City Light and Tacoma City Light.

42 FERC's July 8, 2004 Order, ¶ 126.

43 Northwest Power Pool, Operating Manual, Appendix 1, Contingency Reserve Sharing Procedure, Attachment B, Revised February 5, 2004.

Table IV

FEDERAL SYSTEM SLICE RESOURCES[44]
(MW)

Federal Hydro	19,851
Non- Federally owned Hydro	82
Pumped Storage	314
Fossil Fuel - Coal	-
Fossil Fuel - Other & Misc.	27
Nuclear	1,200
Wind & Solar	205
Geothermal	-
SLICE SYSTEM, TOTAL	21,679
Adjustments, Pivotal Supplier Screen	
planned outages	-
de-rating of hydro capacity	10,935
de-rating of wind and solar capacity	144
operating reserves	527
pumping load	314
CER	387
NET SLICE RESOURCES	9,372

Slice Resources

The capacity of the Federal System Slice Resource Stack is comprised of specific Federal resources, net of certain Federal obligations. The specific Federal resources include the generation from the Federal hydro projects, Columbia Generating Station, Georgia Pacific Corporation's Wauna Mill, Federal Non-Utility Generation; and power deliveries from the CER for Canada contracts. The capacities of these resources and the adjustments for the Federal obligations are shown in Table IV.

PBL makes available 22.63 percent of the net capacity of its Slice Resources available to its customers with Slice contracts. The capacity can be used by Slice customers to meet their own load requirements or to sell to third parties. Therefore, even though BPA may operate all of the Federal system including the Slice Resources, 22.63 percent of those resources are dedicated to Slice customers and not available to PBL for sales into the wholesale market. To account for this limitation on the amount of the Federal system that PBL is able to sell on the wholesale market, we calculated the amount of capacity dedicated to the Slice Resources, taking into consideration all of the necessary adjustments (CER, federal pumping, planned outages, de-rating and operating reserves). We then subtracted 22.63 percent of the adjusted capacity from the capacity available to PBL to meet their sales obligation and added that capacity to the supplies available to Other Suppliers (which includes Slice customers) in the control area.

Long-term Firm Intra-Regional Purchases and Imports

For this analysis, intra-regional purchases are transfers between parties within the BPA control area and parties in other control areas within the PNW, and imports are purchases by parties within the BPA control area from another party outside of the PNW. PBL's contracts for intra-regional purchases and imports with terms of one year or more are treated as long-term firm transactions. These contracts are generally not tied to specific generation. However, as firm contracts, PBL or other purchasers have a right to schedule, and the sellers have an obligation to provide the specified contract quantity to meet the purchasers' loads. Since PBL and other purchasers have control over the dispatch of the capacity associated with these contracts, we have added the contracts' associated capacity to PBL's and the other purchasers' available capacity in the analysis of both market screens.

[44] Non-federally owned hydro resources are hydro resources that are owned by other entities but assigned to or controlled by PBL. The adjustment for CER shown in Table IV is the Canadian Entitlement delivery to Canada less the non-federal CER obligation by other entities. Under current contract provisions, the Federal System Slice Resource stack is further reduced for transmission losses of 3.35 percent. For simplification, we have not taken transmission losses into account in this analysis.

Monthly data for 2003 on PBL's long-term firm intra-regional purchases were obtained from confidential data provided by PBL. PBL has 33 intra-regional contracts with 14 entities for approximately 1,400 MW of average monthly capacity during 2003. Eight of these contracts, representing 491 MW, terminated either during 2003 or at the end of 2003. Five of the contracts have no capacity associated with them reflecting the fact that they are the return contract of an exchange agreement. Under these agreements, PBL provides capacity and energy to a customer during the peak periods and the customer returns the energy in off-peak periods and pays for the use of the capacity in dollars or with additional energy. The capacity associated with many intra-regional contracts varies by month and is usually referred to as the monthly peak load.[45] A review of the load data indicates that the contracts were dispatched at an effective 100 percent load factor during HLH each month. Given the characteristics of these contracts, it is reasonable to add the contract's peak load during the system peak month to PBL's available capacity for the Pivotal Supplier screen analysis. For the Market Share screens, we used the three-month average peak load for the respective season. We had no data for intra-regional transfers for other suppliers. However, transfers between third party Suppliers do not affect the net quantities of supplies available to the Other Suppliers in our analysis.

Monthly data for 2003 imports by PBL and other suppliers in the PNW were obtained from the 2003 Pacific Northwest Loads and Resources Study. PBL had 26 long-term firm import contracts with 12 entities for approximately 250 MW of average monthly capacity during 2003. Four of these contracts, representing 29 MW, terminated during or at the end of 2003. Fifteen of these contracts had no capacity associated with them reflecting exchange energy agreements. All the contracts with associated capacity had a 100 percent load factor during HLH except for three small contracts that expired during 2003. The characteristics of these contracts for imports are very similar to the intra-regional contracts, and imports were treated similarly to intra-regional purchases for both screens. The resulting proxies for intra-regional purchases and imports as well as CER from others (discussed below) are shown in Table V.

Table V

PBL Long-term Firm Purchases and Other Supplies

	Pivotal Screen (MW)	Winter Screen (MW)	Spring Screen (MW)	Summer Screen (MW)	Fall Screen (MW)
Inter-Regional Purchases	1,727	1,611	1,152	1,196	1,489
Imports	289	327	200	163	312
CER From Others	126	154	153	186	220
Total	2,142	2,092	1,505	1,545	2,021

Canadian Entitlement Return From Others

Monthly data for 2003 on the non-Federal Canadian Entitlement obligations delivered to PBL by seventeen entities were provided by PBL. The deliveries are based on a predetermined schedule, which is set by the contract. PBL does not control the delivery of these supplies. Therefore, we decided to treat them differently from the long-term firm purchase contracts. For the Pivotal Supplier screen, the peak delivery during the control area peak month was added to PBL's resource

[45] In all cases PBL will schedule energy up to the contract capacity during heavy load hours when it makes economic sense.

capacity. We are assuming the system peak month deliveries is a reasonable approximation of the capacity PBL can rely on from these contracts to meet its load obligations during peak periods. For the Market Share screens, the average HLH delivery during the relevant seasons is added to PBL's resource capacity. In this case, we assume the average energy deliveries during HLH periods are a reasonable estimate of the capacity PBL could rely on to meet any wholesale sales. For suppliers that provide a portion of their non-Federal Canadian Entitlement from supplies within the BPA control area, their supplies were decreased using the same methodology.

Load Obligations

PBL's Total Load Obligations are the sum of: (a) the proxy Native Load inside and outside the BPA control area; (b) Slice Block sales inside and outside the control area; (c) Block sales; (d) intra-regional sales within PNW and exports from the PNW; and (e) Canadian Entitlement Return.

a. Native Load Proxy

For both market power screens, FERC allows the applicant and competing suppliers to deduct native load commitments from their net generating capacities. For the Pivotal Supplier analysis, the native load proxy is the average of the daily native load hourly peaks during the month in which the annual system peak demand day occurs.[46] For the Market Share analysis, the native load proxy is the minimum peak demand day for a given season.[47] The proxies for native loads were derived from hourly load data for the BPA control area and for the PNW.

The combined load for all suppliers inside the BPA control area was obtained from the TBL's FERC Form 714 filing. The BPA control area data were used to find the system annual peak demand day for the control area. Native load proxies for the combined load of PBL and Other Suppliers within the control area were then calculated using the FERC guidelines. PBL provided detailed hourly data for its native load (DSIs and full and partial requirements customers' loads) inside and outside the BPA control area. We determined PBL's native load proxies using its control area load coincident with the system peak and each season's minimum daily peak. The native load proxies for the Other Suppliers are the differences between the combined control area load proxies and PBL's control area native load proxies. PBL's native load proxies for loads outside the BPA control area are the loads coincident with the control area load proxies. The resulting proxy loads are shown in Table VI.

[46] FERC's April 14, 2004 Order, ¶ 88.

[47] FERC's April 14, 2004 Order, ¶ 92 ¶ 88.

Table VI

PBL Native Load Proxies

Annual Peak and Proxy Loads	Control Area Load (MW)	PBL Load Inside Control Area (MW)	PBL Load Outside Control Area (MW)	Date and Time
BPA Control Area Annual Peak	8,037	5,132	1,303	2/25/03 HE 8
Avg. Daily Peak During Peak Month	7,086	4,459	1,265	NA
Winter Minimum Daily Peak	6,049	4,017	1,111	1/3/03 HE 10
Spring Minimum Daily peak	5,496	3,309	1,082	5/23/03 HE 14
Summer Minimum Daily Peak	5,510	3,446	1,187	8/22/03 HE 11
Fall Minimum Daily Peak	5,020	3,163	1,110	9/12/03 HE 9

The seasonal daily minimal peaks used to determine the system native loads proxies are based on data for all days of the week, except Saturday, Sunday and NERC holidays.[48] The April 14, 2004 and July 8, 2004 FERC Orders did not address whether holidays and weekend days (i.e., Saturday and Sunday) should be omitted from data used to determine proxy loads. However, in an order concerning Puget Sound's market power filing, FERC states: "The Commission hereby clarifies that weekends and NERC holidays may be excluded when determining the peak load day for each season because weekends and holidays are not typical load days."[49]

b. Slice Block Sales

PBL has Slice contracts with 25 customers. Under these contracts, PBL is obligated to provide each customer with a block of energy, 24 hours per day and 7 days per week, that the customer is obligated to take to meet their own base load requirements. This is usually referred to as the "Slice block." In addition, each customer has a right to a fixed percentage of the power generated by PBL's "Slice resources." The sum of all the individual contract percentages equals 22.63 percent of PBL's total Slice resources.

PBL provided monthly data for 2003 on its block sales to the 25 Slice customers. Seventeen of these customers have some or all of their load inside the BPA control area. A review of the data indicates that the deliveries under the Slice Block contracts are constant during each month, which is consistent with the contracts. Given the structure of the data, the logical load proxy to represent these contracts in the Pivotal Supplier screen is their peak load (the same as the average MW load) during the system peak month. For the Market Share screen, we used the contracts' average monthly peak load during the relevant season as the proxy load. Since the capacity changes each month for all of the contracts, the average monthly peak load for the season may not equal the peak load in any month of the season.

Eighteen of PBL's Slice customers have some or all of their load outside the BPA control area. The proxy for the block sales outside the control area were set using the same methodology used to develop a proxy load for block sales inside the control area. For the Pivotal Supplier screen the proxy load is the sum of the contracts' peak loads during the system peak month. The proxy for the Market Share analysis is the average monthly peak load for the relevant season. The data are shown in Table VII.

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[48] NERC holidays are New Year's, Memorial, Independence, Labor, Thanksgiving and Christmas days.

[49] 109 FERC ¶ 61,293, issued December 20, 2004, ¶ 92.

Table VII

PBL Proxy Load for Block Sales (MW)

	Pivotal Screen	Winter Screen	Spring Screen	Summer Screen	Fall Screen
Slice Block Inside Control Area	874	893	725	697	722
Slice Block Outside Control Area	307	314	190	167	294
Block Load Outside Control Area	1,256	1,043	1,067	835	755
Total Block Loads	2,437	2,251	1,982	1,699	1,771

c. Block Sales Outside BPA Control Area

In addition to block sales to Slice customers, PBL also has block sales contracts with three other preference customers, Clark County PUD, Grant County PUD and Tacoma Public Utilities, with loads outside the BPA control area. BPA provided 2003 hourly load data for these block sales. A review of the data indicates that deliveries to Grant were at a constant 100 percent load factor each month, which made it similar to the Slice Block contracts. Deliveries to Clark and Tacoma were not constant because both contracts had an energy component above the block sale amount during HLH periods that could be shaped by the buyer. In addition to a capacity limitation that the buyer could schedule during the HLH, both contracts also had a specified amount of energy in MWH that could be delivered each day. These restrictions prevented the purchaser from scheduling the contract's total capacity at all times during the HLH periods. To maximize their benefits from the contracts both customers maximized their deliveries during HLH periods.

In developing load proxies for these contracts, we decided to treat Grant differently from Clark and Tacoma. Load proxies for Grant were developed using the same methodology used for the Slice Block contracts because of the constant 100 percent load factor shape of the deliveries. In developing load proxies for Clark and Tacoma, we decided to take a conservative approach. Both parties have the right to schedule up to their contract capacity at any hour, and PBL's obligation to deliver limits its ability to resell that capacity on the wholesale market. However, the contract's energy constraints limit the amount of HLH deliveries the parties can schedule. To take this limitation into consideration in both market screens, we have assumed that PBL's load obligations for these contracts are equal to the average load deliveries during heavy load hours. Given this assumption, the proxy loads for Clark and Tacoma used in the Pivotal Supplier analysis is the average daily peak load during the system peak month. This is assumed to be the same as the contract capacity. The proxy load for the Market Share analysis is the average contract load during the HLH periods for the relevant season. This average is invariably less than the contract capacity, which PBL believes to be its true obligation to these customers. The proxy loads for the Block customers are shown in Table VII.

d. Intra-regional Firm Sales

Intra-regional sales are defined here as transactions between PBL and parties outside the BPA control area but within the PNW. During 2003, PBL had 13 such contracts with 9 customers with a combined average monthly peak load of 1,270 MW. The two smallest contracts were with public agencies that are preference customers of PBL with contract terms of 2 to 5 years. Two energy marketers and three IOUs hold the six largest contracts, representing over 97 percent of the load. Two contracts, including the second largest contract for 200 MW, terminated during 2003. There is one exchange contract with no associated capacity that terminated in September 2004. The marketers' and all but one of the IOUs' contracts have a fairly constant 100 percent load factor

during HLH periods. The largest contract, with an average monthly capacity of 838 MW, is energy limited and has a relatively low (40%) load factor during HLH periods. Except for that one, all the other intra-regional contracts have the same characteristics of Slice Block contracts and proxy loads for those intra-regional contracts were developed using the same methodologies.[50] The proxy load for the Pivotal Supplier screen is the peak load during the system peak month. The proxy load for the Market Share analysis is the average monthly peak load during the relevant season.
The largest contract, owned by PacifiCorp, is similar to that of the Grant and Tacoma Block contract and again, being conservative, we defined its proxy load based on the same methodology. The proxy load for the Pivotal Supplier analysis is the peak load (or contract capacity) during the system peak month. For the Market Share analysis we set the proxy loads equal to the average contract load during the HLH periods of the relevant season.[51] The contract energy limitations forced PacifiCorp to schedule their full contract capacity at most 40 percent of the time during HLH periods. Therefore, while PBL has an obligation to provide the full contract capacity during any hour, we used the more conservative load proxy because during most HLH periods PacifiCorp could only schedule the full contract capacity 40 percent of the time. The results are shown in Table VIII.

Table VIII

PBL Proxy Load for Long-term Firm Sales and Deliveries (MW)

	Pivotal Screen	Winter Screen	Spring Screen	Summer Screen	Fall Screen
ITR Sales - PacifiCorp	925	358	352	317	317
Intra-Regional Sales-Others	573	348	348	353	417
Exports	751	619	573	728	642
Canadian Entitlement Return (CER)	513	648	790	948	941
Total	2,763	1,972	2,062	2,347	2,317

e. Exports

Exports are defined as sales to third party customers outside the PNW. Monthly 2003 load data for PBL's and Other Suppliers' export contracts were provided by PBL and are also contained in the 2003 Pacific Northwest Loads and Resources Study. PBL had 28 contracts with 18 entities that averaged approximately 791 MW in 2003. Ten of these contracts representing 97 MW terminated either during or at the end of 2003, while one contract representing 60 MW terminated in October 2004. Eight of the contracts representing 347 MW have effectively a 100 percent load factor during HLH periods. The remaining contracts have load factors ranging from 18 to 80 percent depending on the level of the contract energy limitation. For the contracts without energy limitations, the proxy loads for the Pivotal Supplier screen is the peak load during the system peak month. Proxy loads for the Market Share analysis are the average peak load during HLH periods for the relevant season. For loads under contracts with energy limitations, the proxy load for the Pivotal Supplier analysis is the peak delivery during the system peak month, while the proxy loads for the Market

[50] Slice Block contracts have mandatory take-or-pay provisions, while intra-regional contracts have no take-or-pay provision that obligates the purchaser to schedule the contract quantities at all times.

[51] The capacity associated with most of the contracts varied each month. Therefore, we considered it reasonable to use the average of the heavy load hours demand as a proxy for PBL obligation under the contract.

Share analysis are the average hourly deliveries during the HLH periods of the relevant season. The results are shown in Table VIII.[52]

f. Canadian Entitlement Return

PBL is responsible for delivering to Canada both the Federal and non-Federal Canadian Entitlement obligations. Monthly 2003 data on CER were provided by PBL and are also contained in the 2003 Pacific Northwest Loads and Resources Study. In 2003, the contract's peak load started at 642 MW in the first three months and increased to 1,171 MW for the period April through July and to 1,176 MW during the rest of the year for an annual average peak load of 1,041 MW. These changes were due to the expiration of the Canadian Entitlement Purchase Agreement (CEPA) in April 1, 2003. The CEPA allowed U.S. entities to purchase declining amounts of the energy entitled to Canada under the Columbia River Treaty, or the CER. With the expiration of the CEPA, BPA had to return all of Canada's energy entitlements. The CER contract had an 80 percent load factor during HLH periods, which implies that it had the characteristics of an energy limited contract. However, the Canadians have flexibility in determining the schedule of deliveries up to the contract maximum capacity. Given these characteristics, we developed load proxies for this contract similar to other energy limited long-term firm contracts. The load proxy for the Pivotal Supplier analysis is the peak load during the system peak month while the proxy for the Market Share analysis is the average hourly load during HLH periods for the relevant season. The results are shown in Table VIII.

Potential Additional Imports

FERC defines the relevant market as the control area market where the applicant is physically located and all interconnected first-tier control area markets. Therefore, in assessing the Market screens, FERC allows the applicant to adjust the control area capacity available to meet wholesale sales by the amount of potential imports from these first-tier markets. Potential imports equal the uncommitted capacity in first-tier control areas that can be imported into the relevant control area limited by the control area's simultaneous transmission import capability."[53] Any simultaneous transmission import capability should first be allocated to the applicant's uncommitted remote generation (i.e., capacity in the first-tier control areas). Any remaining simultaneous transmission import capability is then allocated to any uncommitted competing supplies available in the first-tier control areas. FERC did not discuss the issue, but it is also possible to increase the amount of uncommitted supplies by having customers of PBL exports redirecting these supplies to customers within the control area. This is an important source of uncommitted supplies in the BPA control area because of the significant amount of PBL exports leaving the control area.

There are sixteen control areas in the first-tier market.[54] They are listed in Table IX along with our estimates of the uncommitted supplies available in each control area. The uncommitted supplies in these first-tier markets equal the supplies available (i.e., nameplate capacity adjusted for hydro, wind and solar de-rating, operating reserves, and planned outages) less the native load. A review of the results indicates that there is over 12,000 MW of uncommitted capacity available in the first-tier

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[52] Note that exports require a provision for transmission losses because of the long distance the energy has to travel. We ignored these losses in developing our load proxies which implies we are underestimating the amount of capacity necessary to service these export contracts.

[53] FERC's April 14, 2004 Order, ¶ 94.

[54] PacifiCorp has two control areas, PacifiCorp East and PacifiCorp West.

markets at all times to supply wholesale load.[55] The least amount of uncommitted capacity is available during the Summer peak period. Almost all of the uncommitted capacity is in California, which is represented by California ISO and LADWP, with the remainder in Montana.

As noted earlier, TBL has examined the interrelationship of the five major transmission paths into its control area. The study was based on 1 in 20 year peak loading of the Montana and Idaho paths due to the fact that historically these lines have been lightly loaded during peak periods.[56] As a result the TBL study focused on the simultaneous transfer interactions between the two paths from California and the path from Canada. That study was done in 1998 and since then the limits have not presented a problem for BPA. However, this is more likely due to the nature of imports into the PNW. Typically high PNW imports on the NI occur during peak load hours while imports on the COI and the PDCI occur during off-peak hours. Recently, for security reasons, the PDCI has been limited to 2,200 MW compared to the 3,100 MW shown in the nomogram due to the recent reduction in DSI load.[57] The DSI load acted as an interruptible load; in the event of a loss of power on the PDCI path that load could be curtailed to prevent overloading on the parallel COI path. With the large reduction in the DSI load, reliability concerns required the lower rating on the PDCI. Given this new limit on the PDCI, the simultaneous transfer limit at 1,000 MW N-S on the NI results in the COI being limited to 3,675 MW and the PDCI limited to 2,200 MW for a total simultaneous transfer capability of 6,875 MW.[58] To be conservative, the simultaneous transfer capability used in the market screens is 6,500 MW. This number is very conservative since it ignores the transfer capability on the paths from Montana and Idaho on the eastern border of the BPA control area. During peak winter periods the flows along both paths are usually well below their path ratings.[59] This would be consistent with our analysis which indicates that the Idaho market would have no surplus power during peak periods while the Montana market would have at most 1,500 MW to meet its wholesale load (see Table IX). Neither of these control areas would represent a major source of imports into the BPA control area.

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[55] The uncommitted capacity represents the amount of energy available in the control area to compete for the wholesale load. During CAISO's summer peak period, its wholesale load is approximately 10,000 MW and its uncommitted capacity is approximately 9,000 MW, This implies that CAISO would have to rely on imports during its summer peak period which is consistent past experience .

[56] There appears to be very little uncommitted capacity in eastern region of the PNW during peak periods.

[57] The loss of PBL DSI load is reflected in the change in the projected load for 2005, which was 1,750 average MW in the 2001 White Book and is now 292 average MW in 2003 White Book (see 2003 White Book, Table 8 on pg. 36).

[58] The simultaneous transfer limits assume load conditions on the west side of the system do not exceed a 1 in 20 winter peak load conditions.

[59] Based on discussions with TBL staff.

Table IX

Uncommitted Capacity in Control Areas Connected to BPA (MW)

Control Area	BPA Peak Period	BPA Winter Period	BPA Spring Period	BPA Summer Period	BPA Fall Period
Avista Corp.	(220)	35	247	100	39
B.C. Hydro & Power	(1,357)	(628)	1,158	629	(1,072)
California Independent System Operator	15,772	15,840	15,575	8,973	12,892
Chelan County PUD	(1,696)	(1,425)	(349)	(686)	(793)
Douglas County P.U.D.	156	183	264	186	162
Grant County PUD No.2	604	667	695	535	452
Idaho Power Company	(973)	(707)	(586)	(1,622)	(820)
Los Angeles Department of Water and Power	3,241	3,591	3,874	2,900	3,291
North Western Energy (Montana Power Company)	1,437	1,560	1,758	1,551	1,589
PacifiCorp East and PacifiCorp West	205	1,422	2,150	469	1,602
Portland General Electric	(1,201)	(677)	(245)	(387)	(524)
Puget Sound Energy	(2,078)	(1,480)	(803)	(791)	(1,172)
Seattle City Light	(546)	(344)	(64)	(108)	(410)
Sierra Pacific Power Co.	454	583	635	365	566
Tacoma City Light	(296)	(155)	1	(33)	(179)
TOTAL	13,501	18,466	24,311	12,078	15,622

Pivotal Supplier Screen results

The Pivotal Supplier analysis focuses on the applicant's ability to exercise market power unilaterally. It essentially asks whether the market demand can be met absent the applicant's supplies during peak times. Thus, the Pivotal Supplier screen measures market power at peak times, and particularly in spot markets. The applicant is presumed to be pivotal if demand cannot be met without some supply contribution from the applicant.[60]

The proxy for wholesale markets available to PBL and competing suppliers (i.e., "Wholesale Sales") in the BPA control area is the system annual peak load less the sum of the native load proxy for PBL and the Other Suppliers. During 2003, the BPA control area wholesale market proxy was 951 MW. The amount of uncommitted supply available to compete for the marginal supply in the wholesale market equals the total uncommitted capacity available from all suppliers in the control area minus the proxy for Wholesale Sales plus any additional imports and redirected exports (see Table X). The test for passing the Pivotal Supplier screen is a comparison of PBL's uncommitted supplies and the market's uncommitted supplies.

For the Pivotal Supplier analysis, the uncommitted capacity for PBL and Other Suppliers equals their net available supplies less their load obligations. Net available supplies equals nameplate capacity less de-rating for hydro, wind and solar operating reserves, and Slice resource sales, plus proxies for long-term firm intra-regional purchases and imports. Load obligations equal the sum of

[60] FERC's April 14, 2004 Order, ¶ 72.

the load proxies for their native load, Block loads, intra-regional sales, exports and other long-term firm deliveries. Based on the information discussed above, the uncommitted capacity available to compete for the wholesale market in the BPA control area during the 2003 system peak period is 3,127 MW as shown in Table X.

The total capacity available in the control area can be supplemented by imports based on the amount of simultaneous transfer capability available to import additional energy. In the case of the BPA control area, the simultaneous transfer capability is assumed to be 6,500 MW. However, that has to be adjusted to take into consideration PBL transmission capacity requirements for imports under firm contract plus out of area resources, or 2,212 MW.[61] In addition to physically importing energy to compete in the BPA control area wholesale market, other potential suppliers could also reschedule energy exports to customers within the control area. In our analysis, we estimate that there would be 2,763 MW of capacity exports from the BPA control area during the peak month of 2003. This implies that PBL export customers could redirect up to 2,763 MW of additional capacity to compete in the BPA control area independent of the transfer capacity into the control area. Therefore, from imports and redirected exports the total potential supplies available to supplement uncommitted supplies within the control area during the system peak is 7,051 MW. Combining the potential supplies with the Market's uncommitted capacity less the wholesale load proxy results in a net uncommitted supply available to supply marginal wholesale load of 9,226 MW.

In order to pass the screen, PBL's uncommitted capacity would have to be less than the market's net uncommitted supply. The issue of PBL passing this BPA control market screen is moot since its supply is fairly well balanced its load obligations leaving it with no uncommitted capacity during the peak period. The analysis indicates PBL could have a deficit of 730 MW during the peak period if it had to meet all its firm supply obligations. With no uncommitted capacity, PBL's ability to pass the Pivotal Supplier screen is independent of the control area's import capability. In fact, PBL would always pass this market screen as long as the Other Suppliers' uncommitted capacity is greater than the Wholesale load proxy of 951 MW.

The result of the Pivotal Supplier screen analysis is consistent with BPA most recent assessment of its load and resource balance as presented in its 2003 Pacific Northwest Loads and Resources Study. In Exhibit 2 of this study, BPA estimates it would have approximately 850 MW of supply deficit during the peak Winter months of January and February in 2005. It should be noted that the analysis is based on minimal hydro conditions (1937 Water Year), which would reduce the available hydro capacity by about 1,400 MW compared to levels during average hydro conditions.[62] However, the supply deficit derived in the analysis is based on average load conditions, which understates the load during peak periods. An analysis of the 2003 load data indicates that the average hourly load during the Winter period was 5,762 MW, while the average peak day load during the System peak period was 6,897 MW, for a difference of 1,135 MW.

[61] BPA has 70 MW of out of area resources during the peak period of 2003.

[62] Table 6 on page 21 of the Pacific Northwest Loads and Resources Study notes that going from a minimal Water Year to an 80-percentile Water Year increases hydro capacity by 1,835 MW. Therefore, it is reasonable to assume a 50-percentile Water Year would increase hydro capacity by about 1,400 MW.

Table X

BPA MARKET - PIVOTAL SUPPLIER SCREEN (MW)

	Totals	PBL	Other Suppliers
Generating Capacity	26,169	22,228	3,941
de-rating of hydro capacity,	(11,578)	(11,371)	(207)
de-rating of wind,	(157)	(151)	(6)
Operating reserves,	(773)	(533)	(240)
Slice Resource Sales	-	(2,121)	2,121
L-T Firm Purchases and Other Supplies	2,143	2,142	1
Net Available Supplies	15,804	10,194	5,609
Native Load Inside Control Area	(7,086)	(4,459)	(2,627)
Native Load Outside Control Area	(1,265)	(1,265)	-
Block Sales[63]	(1,563)	(2,437)	874
L-T Firm Sales and Other Deliveries	(2,763)	(2,763)	-
Uncommitted Capacity	3,127	(730)	3,857
Proxy for Wholesale Load	(951)		
Potential Additional Imports	7,051		
Net Uncommitted Supply	9,226		
PBL Uncommitted Capacity	(730)		
Net Uncommitted Supply less PBL	9,956		
If Positive PASS, If Not FAIL	PASS		

Market Share Screen Results

The Market Share analysis focuses on whether the applicant has a dominant position in the market, which is another indication of whether the applicant has unilateral market power and may indicate the potential to facilitate coordinated interaction with other sellers. The Market Share screen measures an applicant's size relative to others in the market during each of the four seasons, Summer, Fall, Winter and Spring.[64] FERC's Market Share analysis adopts an initial threshold of 20 percent. That is, a supplier who has less than a 20 percent market share in the relevant market in each of the four seasons will be considered to have passed the screen.[65] The 20 percent threshold is consistent with § 4.134 of the U.S. Department of Justice 1984 Merger Guidelines issued June 14, 1984, reprinted in Trade Reg. Rep. P13,103 (CCH 1988).[66]

For the Market Share analysis, the relevant market is defined as the total (i.e., PBL's plus Other Suppliers') uncommitted capacity available in the control area plus any potential additional imports.

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[63] PBL's block sales to Slice Customers are considered additional resources to Other Suppliers which include Slice Customers.

[64] The months in each of the four seasons considered are: Summer (June/July/August); Fall (September/October/November); Winter (December/January/February); and Spring (March/April/May). [FERC's April 14, 2004 Order, Footnote 85].

[65] FERC's April 14, 2004 Order, ¶ 102.

[66] FERC's April 14, 2004 Order, Footnote 86.

The calculation of the uncommitted capacity is similar to that of the Pivotal Supplier analysis except the supply levels and load proxies reflect conditions during the relevant seasons instead of the system peak period. PBL's market share is then calculated as its uncommitted capacity as a percent of the relevant market total uncommitted supply for each of the four seasons.
The results for each season are shown in Table XI.

Table XI

BPA MARKET - MARKET SHARE SCREENS

	Winter Screen	Spring Screen	Summer Screen	Fall Screen
Market's Uncommitted Capacity (MW)	5,174	5,017	4,863	3,961
Potential Additional Imports (MW)	6,310	6,985	7,234	6,740
Net Uncommitted Supply (MW)	11,484	12,001	12,097	10,701
PBL Uncommitted Capacity (MW)	748	1,027	828	73
PBL Market Share	7%	9%	7%	1%
If Less than 20% PASS, If Not FAIL	PASS	PASS	PASS	PASS

The results of the analysis clearly show that PBL is significantly below the threshold for having market power in its control area. During the Spring season, PBL had the highest amount of uncommitted capacity relative to the total uncommitted supply in the control area (21%).[67] However, given the ability to import at least 150 MW of additional supplies based on the physical simultaneous import capability of the TBL transmission system and/or displacement of exports, PBL's market share drops below the threshold.

analysis of pnw market

In its July 8, 2004 Order, FERC allowed applicants located within the Western interconnect to make a case that a larger geographic market definition is appropriate for the Market Screen analyses. BPA believes that the larger Pacific Northwest market is the appropriate market for assessing its ability to exert market power. BPA, and more specifically its marketing subsidiary, PBL, has firm power sales contracts with customers in every control area in the PNW except Alberta Electric in Canadian.[68] During peak periods, over 40 percent of PBL's firm sales go to customers outside its control areas either in the PNW or California (see Table XII).[69] In addition, as we noted earlier, the BPA control area is physically connected to every other control area in the PNW. BPA total integration into the PNW is highlighted by its annual publication of the Pacific Northwest Loads and Resources Study. The report summarizes the results of a ten (10) year study that simulates the operation of the power system under the Pacific Northwest Coordination Agreement. The study projects the yearly average energy consumption and resource availability for the 10-year study period. For BPA, the Pacific Northwest Loads and Resources Study establishes one of the planning bases for supplying electricity to customers.

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[67] The 21% results from dividing PBL's uncommitted supply of 1,027 MW by total uncommitted supply in the control area 5,017 MW.

[68] PBL has no direct connection to Alberta Electric control area.

[69] This includes full and partial requirements customers, block customers and customers with long-term firm contracts.

Table XII

PBL Long Term Firm Sales Distribution During 2003 Peak

Customer Group	Inside BPA Control Area	Outside BPA Control Area	Total
Native Load	5,132	1,426	6,558
Slice Load	1,445	669	2,114
Slice Block Sales	874	307	1,181
Block Sales		1,256	1,256
Inter-Regional Sales		925	925
Exports		751	751
TOTAL	7,451	5,334	12,785
Distribution	58%	42%	

Conducting the Market Screen analyses for the PNW market is a repeat of the analyses done for the BPA control area except the loads and resources of the Other Suppliers are expanded to include those of suppliers in the other control areas of the PNW. PBL resources and loads used in the Market Share screens will only change to reflect the coincident peaks of the PNW region instead of the BPA control area.

PNW Capacity Available for Wholesale Sales

The capacity available for the PNW Wholesale market is equal to Net Supplies Available less Total Load Obligation for all suppliers in the region. We have already discussed the capacity available to PBL. Therefore the following discussion will focus on the Other Suppliers.

Available Supplies

Information on the generating capacity of suppliers in the PNW was obtained from the WECC, PNUCC, the BPA Pacific Northwest Loads and Resources Study and other sources. The resulting data are illustrated in Table XIII below.

Table XIII

Generation Power Plant Nameplate Capacity in the PNW (MW)

Type of Power Plant	PBL Controlled Power Plants	Partial Req. Customers Power Plants	Other Suppliers Power Plants	Total Power Plants Within the PNW
Federal Hydro	20,131	-	-	20,131
Non- Federal Hydro	123	178	13,024	13,325
Federal Pumped Storage	314	-	-	314
Fossil Fuel – Coal	-	-	12,052	12,052
Fossil Fuel - Other & Misc.	71	6	9,168	9,245
Nuclear	1,200	-	-	1,200
Wind & Solar	206	-	513	719
Geothermal	-	-	195	195
TOTAL	22,045	183	34,952	57,180

The table indicates that the nameplate capacity of generation resources marketed by PBL represents approximately 39 percent of the generation nameplate capacity of power plants in the PNW. However, as we have noted earlier, nameplate capacity is not a good indicator of the available capacity, especially for hydroelectric power plants. Following FERC's guidelines, we de-rated hydro and wind facilities in the PNW based on the last five years of hydro operations and available data for wind generation. We also adjusted both PBL's and Other Suppliers' capacity for operating reserves and planned outages using the same methodology discussed earlier for the BPA market screens.

Data on Other PNW Suppliers' long-term firm imports into the PNW was obtained from BPA 2003 Pacific Northwest Loads and Resources Study.[70] An analysis of the data indicates that Other Suppliers had an average of 738 MW of capacity under firm long-term import contracts during 2003. The capacity was utilized at a 51 percent capacity factor during heavy load hours. The relatively low utilization does not change the fact that the purchaser had the right to schedule the contract's full capacity at any time. Therefore, we assumed for both the Pivotal Supplier and the Market Share screens that the purchasers had access to the full contract capacity, which was added to the suppliers of the Other Suppliers in the market.

Load Proxies

The methodology used to develop load proxies for the PNW is similar to the ones described above for the BPA market. Hourly load data for the PNW region during 2003 was obtained from PBL. An analysis of the data indicates that the annual peak of the PNW system is coincident with the peak of the BPA control area. The 2003 peak load for the PNW region was 33,580 MW and the average daily peak during the February peak month was 31,638 MW resulting in a proxy wholesale load of 1,941 MW (see Table XIV).

Table XIV

PNW Native Load Proxies

Annual Peak and Proxy Loads	Control Area Load (MW)	PBL Load Inside Control Area (MW)	Date and Time
PNW Control Area Annual Peak	33,580	6,435	2/25/2003 HE 8
Avg. Daily Peak During Peak Month	31,638	5,725	NA
Winter Minimum Daily Peak	28,049	4,912	12/24/2003 HE 10
Spring Minimum Daily Peak	25,950	4,356	5/22/2003 HE 11
Summer Minimum Daily Peak	26,884	4,473	7/3/2003 HE 15
Fall Minimum Daily Peak	25,140	4,280	9/19/2003 HE 11

In the analysis of both PNW screens, the load proxy for intra-regional sales by PBL are treated as supply additions for Other Suppliers and supply additions due to intra-regional purchases by PBL are treated as loads due to long-term sales by Other Suppliers. Data on Other Suppliers' exports from the PNW was also obtained from BPA Pacific Northwest Loads and Resources Study. Analysis of the data indicates that Other Suppliers had long-term firm contracts to export, on average, 801 MW of capacity in 2003. Their average hourly export was 675 MW for an 84 percent capacity factor. To be conservative, we assumed that buyers have control in terms of scheduling deliveries under the contracts. Therefore, in both screen analyses the load associated with these export contracts equals their peak delivery during the system peak month for the Pivotal Supplier screen and the average monthly peak delivery for the relevant season in the Market Share screen. The proxies for Other Suppliers' imports and exports are shown in Table XV.

[70] Intra-regional transfers between Other Suppliers have no impact on the overall supplies available in the region, and any intra-regional sale or purchase by PBL results in a purchase or sale, by the Other Suppliers.

Table XV

Other PNW Suppliers' Transactions (MW)

	Pivotal Screen	Winter Screen	Spring Screen	Summer Screen	Fall Screen
Exports	686	704	696	944	861
Imports	979	1,106	573	388	884

Potential Imports

In the case of the PNW market, the main first-tier control areas consist of BC Hydro to the north, and CAISO and LADWP to the south. To the east PNW is interconnected to the Mid-Continent Area Power Pool (MAPP), through a number of small DC transmission lines whose combined rating is approximately 700 MW.[71] Since the transfer capability on this path is relatively small, control areas to the east of the PNW were ignored and our analysis only considered the three major control areas to the north and south. A review of Table XVIindicates that only the CAISO and LADWP are able to provide any significant amount of additional supplies to the PNW region. The two regions have approximately 20,000 MW of uncommitted capacity during the winter and spring seasons and approximately 12,000 MW in the summer and fall. In the summer the uncommitted capacity reduces to around 11,000 MW. It should be emphasized that uncommitted capacity does not represent surplus energy but energy that is available to compete for wholesale load in the primary control area and all connected markets. Given the large size of the BPA control area, the five major paths into its system are the same major paths into the PNW. Therefore, we have used the same simultaneous transfer capability for the PNW that we used for the BPA control area based on the same set of paths.

Table XVI

Uncommitted Capacity in Control Areas Connected to PNW (MW)[72]

Control Area	Peak Period	Winter Period	Spring Period	Summer Period	Fall Period
B.C. Hydro & Power	(1,357)	(626)	1,158	629	(561)
California Independent System Operator	15,772	16,062	15,575	8,973	9,860
Los Angeles Department of Water and Power	3,241	3,625	3,874	2,900	3,104
TOTAL	17,655	19,061	20,608	12,501	12,403

Results of Market Screens

The results of the Pivotal Supplier screen for the PNW market are illustrated in Table XVII. The table reaffirms the earlier results of the BPA control area screen that PBL does not have market power during peak periods. As was noted earlier, PBL does not appear to have any uncommitted capacity during the BPA control area peak period which is the same as the PNW peak period in 2003. Therefore, it will not have the supplies to exert market power during peak periods.

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[71] WECC Power Supply Assessmet, June 16, 2004.

[72] The uncommitted capacity for the control areas differ from Table IX because the time of the seasonal peaks in the PNW differ from that of the BPA control area.

Independent of BPA uncommitted suppliers, if Other Suppliers have uncommitted supplies exceeding Wholesale proxy load of 1,941 MW, then BPA will automatically pass this screen. Given the large amount of uncommitted supplies held by Other Suppliers in the PNW market it would be difficult for BPA to exert market power during peak periods in the PNW.

Table XVII

PNW MARKET - PIVOTAL SUPPLIER SCREEN (MW)

	Totals	PBL	Other Suppliers
Generating Capacity	57,180	22,228	34,952
de-rating of hydro capacity,	(17,964)	(11,371)	(6,592)
de-rating of wind,	(511)	(151)	(360)
Operating reserves,	(2,247)	(533)	(1,715)
Slice Resource Sales	-	(2,121)	2,121
L-T Firm Purchases and Other Supplies	4,494	2,142	2,352
Available Supplies	40,952	10,194	30,758
Native Load Inside PNW	(31,638)	(5,725)	(25,914)
Block Sales	-	(2,437)	2,437
L-T Firm Sales and Other Deliveries	(5,175)	(2,763)	(2,413)
Uncommitted Capacity	4,139	(730)	4,869
Proxy for Wholesale Load	1,941		
Potential Additional Imports	8,450		
Net Uncommitted Supply	10,647		
PBL Uncommitted Capacity	(730)		
Net Uncommitted Supply less PBL	11,377		
If Positive PASS, If Not FAIL	PASS		

The results of the Market Share screen for the PNW market are illustrated in Table XVIII. The results of the Market Share screen once again show that PBL is significantly below the threshold for having market power, this time in the PNW market. This is not surprising since PBL did not have market power in the BPA control area where most of its resources are located. In the PNW market, PBL's highest market shares occur in the Winter, which is the peak demand period for the region, and in the Summer. PBL's highest share of the PNW market's uncommitted capacity (15 percent) occurs in the Summer season.[73] Therefore, if we were to ignore imports in this market share analysis, PBL's highest market share would be only 15 percent and it would still pass the market screen.

[73] The 15% results from dividing PBL's uncommitted supply of 988 MW by total uncommitted supply in the region 6,562 MW.

Table XVIII

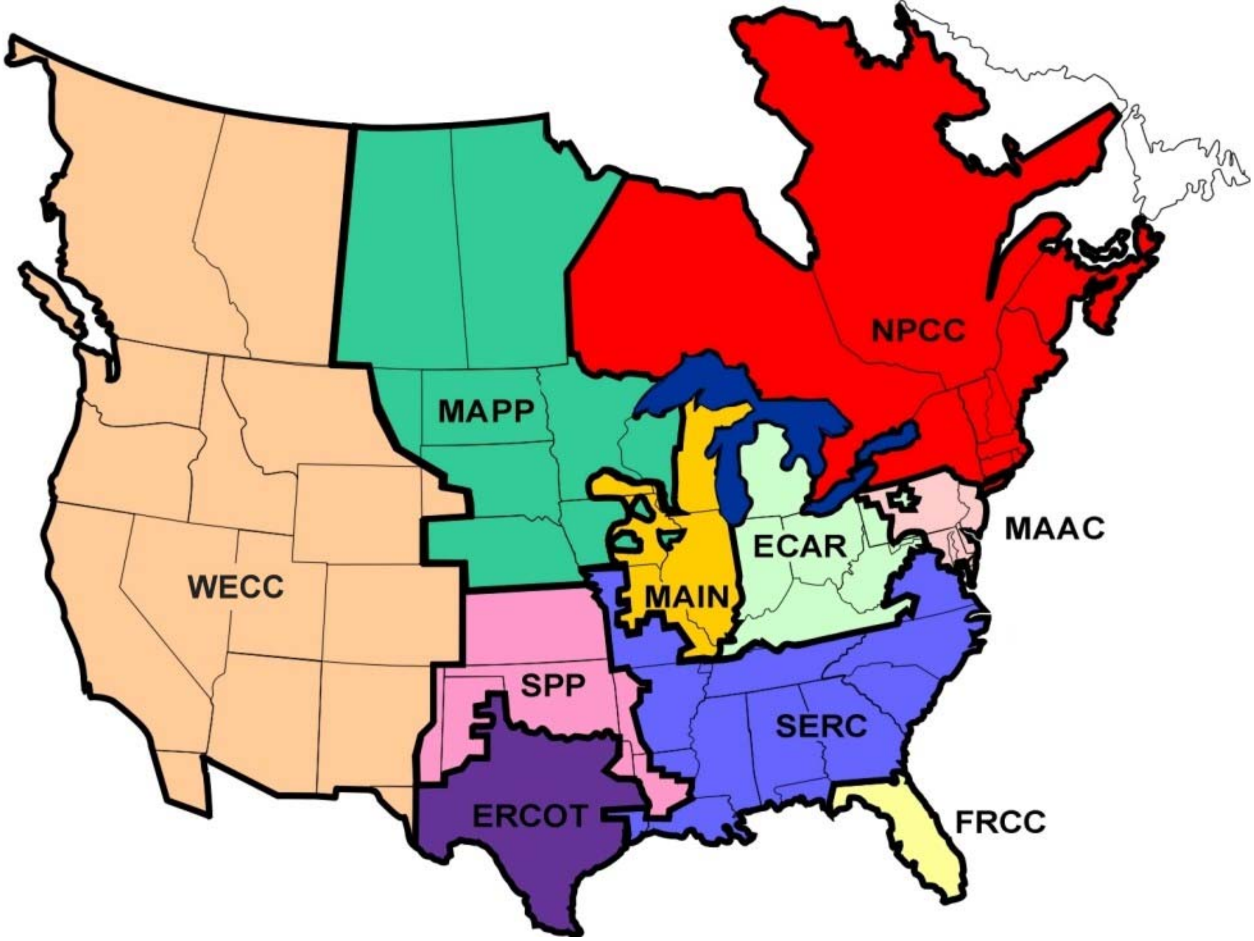
PNW MARKET - MARKET SHARE SCREENS

	Winter Screen	Spring Screen	Summer Screen	Fall Screen
Market's Uncommitted Supply (MW)	7,760	8,839	6,562	6,144
Potential Additional Imports (MW)	7,037	7,785	8,569	7,748
Net Uncommitted Supply (MW)	14,796	16,624	15,131	13,892
PBL Uncommitted Supply (MW)	964	1,063	988	66
PBL Market Share	7%	6%	7%	0%
If Less than 20% PASS, If Not FAIL	PASS	PASS	PASS	PASS

Conclusions

This Market Power Study has analyzed the whether the marketing division of BPA has the ability to exert market power based on two screens recently proposed by the Federal Energy Regulatory Commission. PBL passes both the Pivotal Supplier screen and the Market Share screen in both the BPA control area market and the larger PNW market. The Pivotal Supplier analysis examines the ability of PBL to exert market power during the peak winter period in both markets. The results indicate that the capacity of PBL's dependable long-term supplies matches its long-term contract capacity obligations during the peak periods. Therefore, instead of exerting market power, PBL may have to acquire some limited amount of short-term supplies if it were required to meet all its contracted long-term capacity obligations during the winter peak periods. The Market Share analysis examines the ability of PBL to exert market power alone or in combination with Other Suppliers during each of the four seasons of the year. The analysis calculates PBL's market share in each season and compares it to a 20 percent threshold. PBL passed the test in all seasons in both the BPA control area market and the larger PNW market. In passing the screen for the PNW market, PBL need not rely on any potential imports into that market. In the case of the BPA control area market, passing the Market Share screen requires the availability of 150 MW of import capacity. However, a very conservative estimate of the simultaneous import capability for the BPA control area is 6,500 MW. Based on the principles established in the April 4 Order and the July 8 Order, PBL does not possess horizontal generation market power in either BPA control area market, or in the broader PNW market.

Figure 1: Map of NERC Regions



East Central Area Reliability Coordination (ECAR)
Electric Reliability Council of Texas (ERCOT)
Florida Reliability Coordinating Council (FRCC)
Mid-Atlantic Area Council (MAAC)
Mid-America Interconnected Network (MAIN)
Mid-Continent Area Power Pool (MAPP)
Northeast Power Coordinating Council (NPCC)
Southeastern Electric Reliability Council (SERC)
Southwest Power Pool (SPP)
Western Electric Coordination Council (WECC)

Figure 2: Pacific Northwest Control Areas and Utility District Boundaries

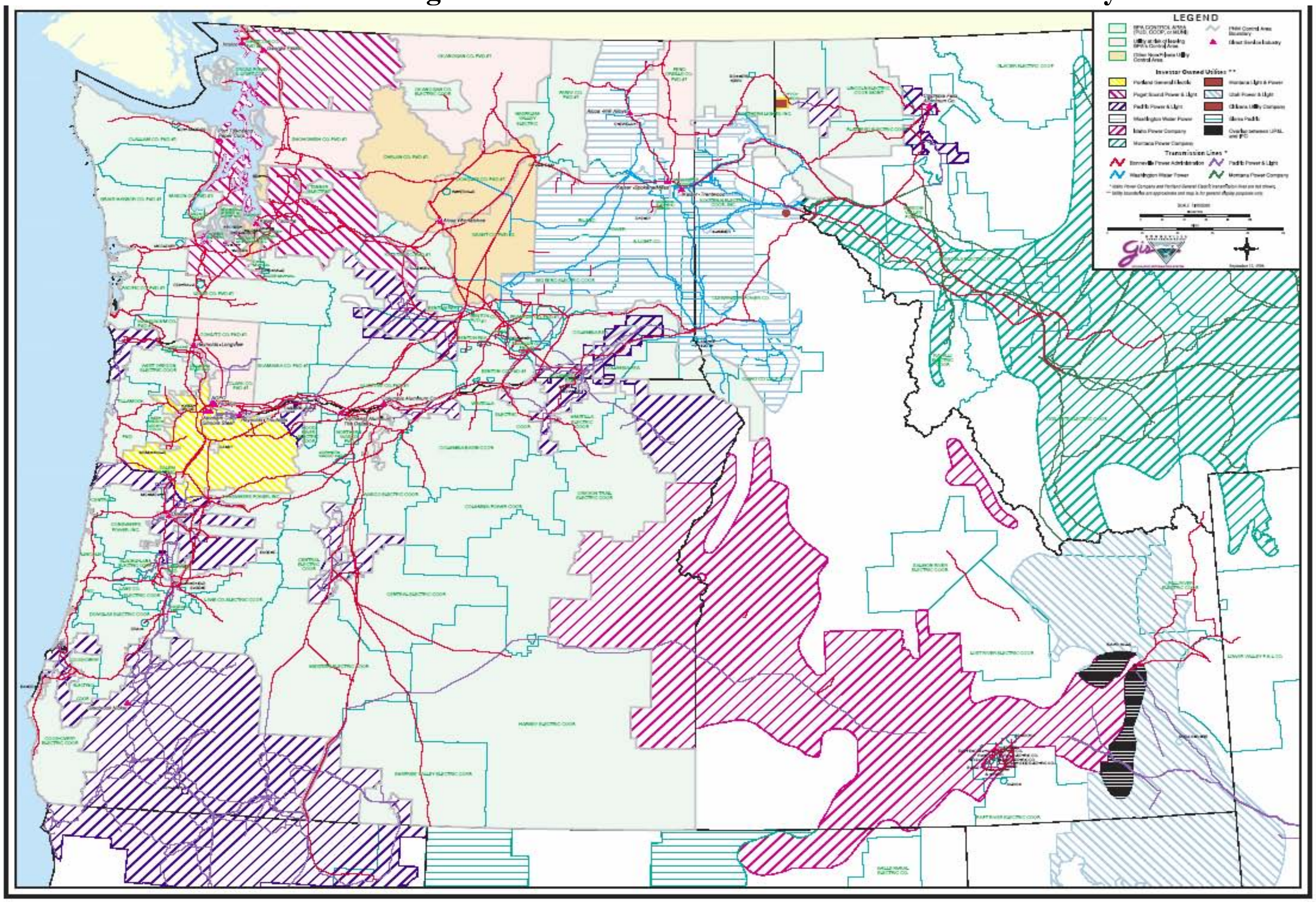
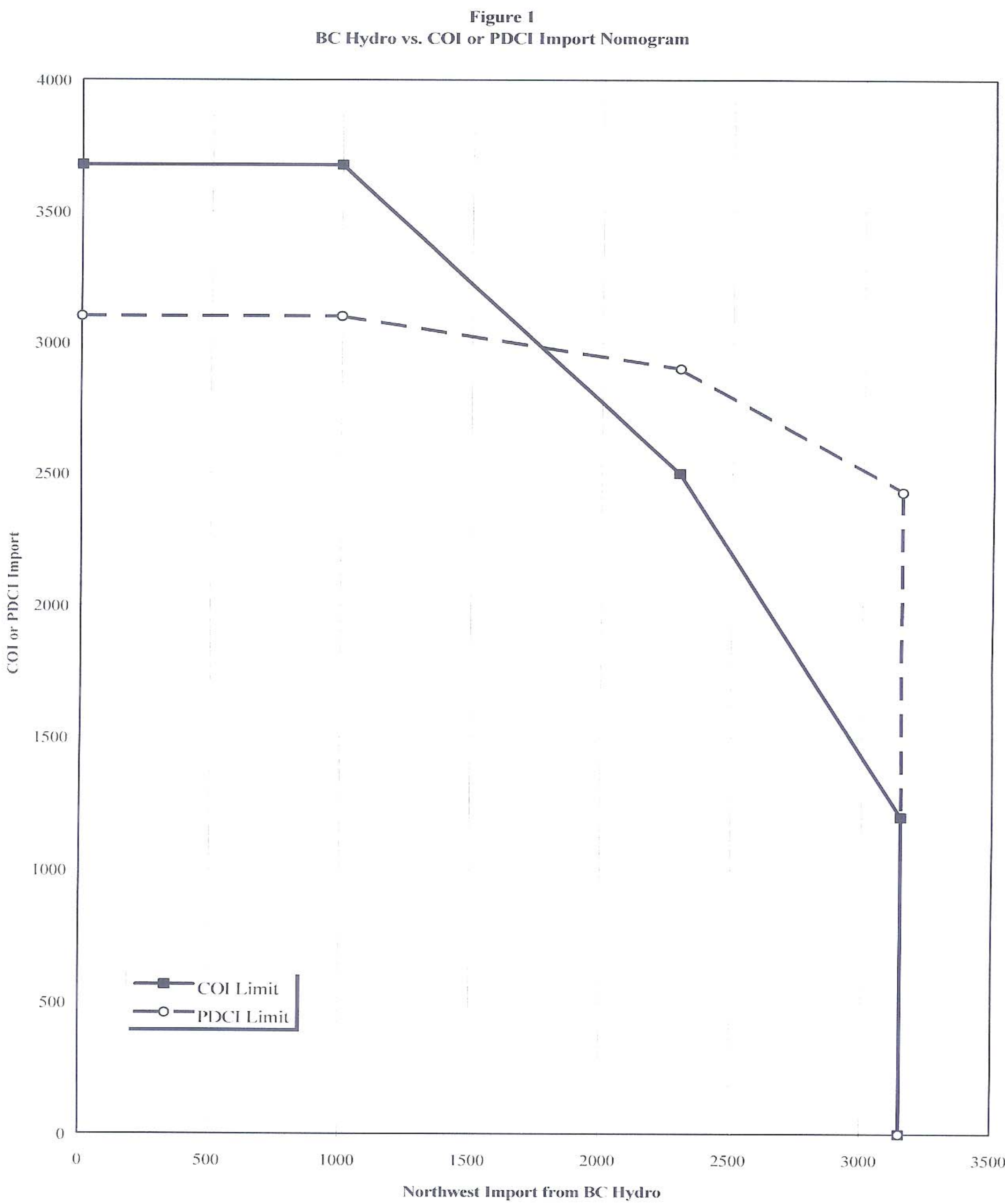


Figure 3: PNW Nomogram



Appendix A: WECC Sub-regions and Control Areas

AZNMSNV	Arizona Public Service Company	AZPS
	DECA, LLC - Arlington Valley	DEAA
	El Paso Electric	EPE
	Imperial Irrigation District	IID
	Nevada Power Company	NEVP
	Public Service Company of New Mexico	PNM
	Salt River Project	SRP
	Tucson Electric Power Company	TEPC
	Western Area Power Administration – DSW	WALC
CAMX	California Independent System Operator	CAISO
	Comision Federal de Electricidad	CFE
	Los Angeles Department of Water and Power	LDWP
	Sacramento Municipal Utility District	SMUD
NWPP	Alberta Electric Supply Company, LLC	AESO
	Avista Corp.	AVA
	B.C. Hydro & Power Authority	BCHA
	Bonneville Power Administration Transmission	BPAT
	Chelan County PUD	CHPD
	Grant County PUD No.2	GCPD
	Idaho Power Company	IPCO
	Montana Power Company	MPCO
	P.U.D. No. 1 of Douglas County	DOCA
	PacifiCorp-East	PACE
	PacifiCorp-West	PACW
	Portland General Electric	PGE
	Puget Sound Energy Transmission	PSEI
	Seattle City Light	SCL
	Sierra Pacific Power Co. – Transmission	SPPC
	Tacoma Power	TPWR
	Western Area Power Administration – UGPR	WAUM
RMPA	Public Service Company of Colorado	PSCO
	Western Area Power Administration – CM	WACM

Source: http://www.nerc.com/~filez/ctrlareas/acronymsPage4.html (Downloaded 9/9/04, Information dated November 5, 2002)

Appendix B: Slice System

1. **HYDROELECTRIC PROJECTS**

(a) Projects Currently with Flexibility

Mica (storage only, no at-site generation)
Arrow (storage only, no at-site generation)
Duncan (storage only, no at-site generation)
Grand Coulee
Chief Joseph
McNary
John Day
The Dalles
Bonneville
Lower Granite
Little Goose
Lower Monumental
Ice Harbor
Big Creek

(b)..Cyclic Projects

Dworshak
Hungry Horse
Libby
Albeni Falls

(c) ....Minor Projects

Chandler
Cowlitz Falls
Roza

(d)..Southern Idaho Projects

Anderson Ranch
Black Canyon
Boise Diversion
Idaho Falls Projects
Minidoka
Palisades

(e) ....Willamette Projects

Big Cliff
Cougar
Detroit
Dexter
Foster

Green Peter
Hills Creek
Lookout Point
Lost Creek

2. THERMAL AND MISCELLANEOUS RESOURCES
CGS (formerly WNP-2)
Wauna
Foote Creek Wind Turbine Projects
Grand Coulee Pumps
Dworshak/Clearwater Small Hydro Power
Green Springs
Stateline (90.42 MW of installed capacity and associated energy)
Condon
Klondike
Ashland Police Station Solar
White Bluff
Fourmile Geothermal Project (Available in 2006)

3. CONTRACTS

Non-Treaty Storage Agreement
Chief Joseph Encroachment
Albeni Falls Encroachment

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