2007 WHOLESALE POWER RATE SCHEDULES

2007 GENERAL RATE SCHEDULE PROVISIONS

November 2006

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

BONNEVILLE POWER ADMINISTRATION

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

United States Department of Energy
Bonneville Power Administration
905 N.E. 11th Avenue
Portland, OR 97232

Bonneville Power Administration's (BPA) 2007 Wholesale Power Rate Schedules and General Rate Schedule Provisions (GRSPs), effective October 1, 2006, and contained herein, were approved on an interim basis by the Federal Energy Regulatory Commission (FERC) on September 21, 2006. *U.S. Dep't of Energy – Bonneville Power Admin.*, 116 FERC ¶ 61,264 (2006).

❖

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

The General Transfer Agreement (GTA) Delivery Charge was approved on a final basis, effective October 1, 2005, through September 30, 2007, by FERC on September 29, 2005. *U.S. Dep't of Energy – Bonneville Power Admin.*, 112 FERC ¶ 62,258 (2005).

❖

These rate schedules and General Rate Schedule Provisions include all errata corrections as of the date of publication.

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

This page intentionally left blank.

BONNEVILLE POWER ADMINISTRATION
RATES
TABLE OF CONTENTS

Acronym List ii

2007 Wholesale Power Rate Schedules (WP-07) 1

2007 General Rate Schedule Provisions (GRSPs)..... 65

❖

Appendix A. 2002 Slice Rate Methodology 137

❖

Appendix B. Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up 147

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

ACRONYM LIST

AGC	Automatic Generation Control
aMW	Average Megawatt
ANR	Accumulated Net Revenues
ASC	Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
C/M	Consumers/Mile of Line for Low Density Discount
COB	California-Oregon Border
CRC	Conservation Rate Credit
CSP	Customer System Peak
CY	Calendar Year (Jan-Dec)
DJ	Dow Jones
DSIs	Direct Service Industrial Customers
EN	Energy Northwest
Energy Northwest	Formerly Washington Public Power Supply System (Nuclear)
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FERC	Federal Energy Regulatory Commission
FPS	Firm Power Products and Services (rate)
FY	Fiscal Year (Oct-Sep)
GAAP	Generally Accepted Accounting Principles
GEP	Green Energy Premium
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GTA	General Transfer Agreement
HLH	Heavy Load Hour
IOU REP Settlement benefits	Investor-Owned Utilities Residential Exchange Program Settlement benefits
IOUs	Investor-Owned Utilities
IP	Industrial Firm Power (rate)
K/I	Kilowatt-hour/Investment Ratio for Low Density Discount
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatt-hour
LB CRAC	Load-Based Cost Recovery Adjustment Clause
LDD	Low Density Discount
LLH	Light Load Hour
LME	London Metal Exchange
Mid-C	Mid-Columbia
MW	Megawatt (1 million watts)
MWh	Megawatt-hour

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

NERC	North American Electric Reliability Council
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
NOB	Nevada-Oregon Border
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NR	New Resource Firm Power (rate)
NWPP	Northwest Power Pool
O&M	Operation and Maintenance
PBL	Power Business Line
PF	Priority Firm Power (rate)
PNCA	Pacific Northwest Coordination Agreement
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection
POM	Point of Metering
Project Act	Bonneville Project Act
REP	Residential Exchange Program
ROD	Record of Decision
RTF	Regional Technical Forum
SCRA	Supplemental Contingency Reserve Adjustment
Slice	Slice of the System product
TAC	Targeted Adjustment Charge
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
UAI Charge	Unauthorized Increase Charge
USBR	U.S. Bureau of Reclamation
WECC	Western Electricity Coordinating Council
WSCC	Western Systems Coordinating Council
WSPP	Western Systems Power Pool

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

2007 WHOLESALE POWER RATE SCHEDULES

BONNEVILLE
POWER ADMINISTRATION

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

INDEX
2007 POWER RATE SCHEDULES
(WP-07)

PF-07	Priority Firm Power Rate	5
NR-07	New Resource Firm Power Rate	29
IP-07	Industrial Firm Power Rate	49
FPS-07	Firm Power Products and Services Rate	55
GTA	General Transfer Agreement Delivery Charge	63

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

SCHEDULE PF-07
PRIORITY FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of Firm Power to be used within the Pacific Northwest (PNW). Priority Firm (PF) Power may be purchased by public bodies, cooperatives, and Federal agencies for resale to ultimate consumers, for direct consumption, and for Construction, Test and Start-Up, and Station Service. Rates in this schedule are in effect beginning October 1, 2006, and apply to purchases under requirements' Firm Power sales contracts for a three-year period. The Slice Product is only available for public bodies and cooperatives who have signed Slice contracts for the FY 2002-2001 period. Utilities participating in the Residential Exchange Program (REP) under Section 5(c) of the Northwest Power Act may purchase Priority Firm Power pursuant to the Residential Exchange Program. Rates under contracts that contain charges that escalate based on BPA's Priority Firm Power rates shall be based on the three-year rates listed in this rate schedule in addition to applicable transmission charges.

Cited in Pacific Northwest Generating v. DOE No. 05-75638 archived on December 17, 2008

This rate schedule supersedes the PF-02 rate schedule, which went into effect October 1, 2001. Sales under the PF-07 rate schedule are subject to BPA's 2007 General Rate Schedule Provisions (2007 GRSPs). Products available under this rate schedule are defined in the 2007 GRSPs. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's 2007 GRSPs and billing process.

For ease of reference, BPA uses the term PF rate and PF Preference rate interchangeably.

SECTION II. RATES TABLES

The rates in this section apply to PF products as shown in Section IV. The PF Exchange rate is shown in Section III.

A. DEMAND RATE

1. Monthly Demand Rate for FY 2007 through FY 2009

1.1 Applicability

These monthly rates apply for the rate period for customers purchasing Firm Power. These monthly rates are also used to implement the Pre-Subscription Contracts.

Cited in Pacific Northwest Generating v. DOE, No. 05-75028 archived on December 17, 2008

1.2 Rate Table

Applicable Months	*Rate*
January	$1.85 per kW
February	$1.88 per kW
March	$1.75 per kW
April	$1.64 per kW
May	$1.36 per kW
June	$1.25 per kW
July	$1.53 per kW
August	$1.79 per kW
September	$1.85 per kW
October	$1.94 per kW
November	$2.08 per kW
December	$2.18 per kW

B. ENERGY RATE

1. Monthly Energy Rates for FY 2007 through FY 2009

1.1 Applicability

These rates apply for the rate period for customers purchasing Priority Firm Power. These rates are used to implement the Pre-Subscription Contracts.

1.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	28.07 mills/kWh	20.30 mills/kWh
February	28.66 mills/kWh	20.56 mills/kWh
March	26.59 mills/kWh	19.49 mills/kWh
April	24.95 mills/kWh	17.93 mills/kWh
May	20.84 mills/kWh	14.41 mills/kWh
June	18.87 mills/kWh	10.02 mills/kWh
July	23.24 mills/kWh	17.01 mills/kWh
August	27.21 mills/kWh	20.18 mills/kWh
September	28.09 mills/kWh	22.54 mills/kWh
October	29.70 mills/kWh	21.76 mills/kWh
November	31.68 mills/kWh	23.10 mills/kWh
December	33.06 mills/kWh	24.26 mills/kWh

Cited in Pacific Northwest Generating v. DOE No. 05-75638 archived on December 17, 2008

C. LOAD VARIANCE RATE

The Load Variance Rate for FY 2007 through FY 2009 applies to all customers purchasing power under this rate schedule unless specifically excluded in Section IV below. The rate for Load Variance is 0.47 mill/kWh.

D. SLICE RATE

1. Applicability

This rate applies to customers purchasing the Slice Product. This rate will remain constant during the rate period.

2. Rate

The monthly rate for the Slice Product is $1,877,054 per 1 percent of Slice.

SECTION III. PF EXCHANGE RATE TABLES

The rates in this section apply to sales under the Residential Exchange Program.

A. DEMAND RATE

1. PF Exchange Monthly Demand Rate for FY 2007 through FY 2009

1.1 Applicability

These monthly rates apply to customers purchasing power under the Residential Exchange Program.

1.2 Rate Table

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Applicable Months	*Rate*
January	$1.85 per kW
February	$1.88 per kW
March	$1.75 per kW
April	$1.64 per kW
May	$1.36 per kW
June	$1.25 per kW
July	$1.53 per kW
August	$1.79 per kW
September	$1.85 per kW
October	$1.94 per kW
November	$2.08 per kW
December	$2.18 per kW

B. ENERGY RATE

1. PF Exchange Energy Rates for FY 2007 through FY 2009

1.1 Applicability

These rates apply to customers purchasing power under the Residential Exchange Program.

1.2 Rate Table

Applicable Months	*Rate*
January	46.43 mills/kWh
February	47.32 mills/kWh
March	45.45 mills/kWh
April	37.43 mills/kWh
May	32.92 mills/kWh
June	31.51 mills/kWh
July	38.85 mills/kWh
August	43.52 mills/kWh
September	45.72 mills/kWh
October	42.32 mills/kWh
November	49.35 mills/kWh
December	51.89 mills/kWh

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

C. LOAD VARIANCE RATE

The Load Variance Rate for FY 2007 through FY 2009 applies to all customers purchasing power under this rate schedule unless specifically excluded in Section IV.H below. The rate for Load Variance is 0.47 mill/kWh.

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

SECTION IV. PRODUCT LIST

The rates described above apply to the following products.

Section IV.A. Full Service Product

Section IV.B. Actual Partial Service Product – Simple

Section IV.C. Actual Partial Service Product – Complex

Section IV.D. Block Product

Section IV.E. Block Product with Factoring

Section IV.F. Block Product with Shaping Capacity

Section IV.G. Slice Product

Section IV.H. PF Exchange Power

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

A. FULL SERVICE PRODUCT

Purchases of the Core Subscription Full Service Product are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Measured Demand on the monthly Generation System Peak (GSP)
as specified in the contract
multiplied by
the Demand Rate from Section II.A.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible Priority Firm Power (PF) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

Cited in Pacific Northwest Generating v. DOE, No. 03-75638 archived on December 17, 2008

Note: The Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up GRSP from the FY 2002-2006 rate period will continue into the beginning of FY 2007. See Appendix B.

B. ACTUAL PARTIAL SERVICE PRODUCT - SIMPLE

Purchases of the Core Subscription Actual Partial Service Product – Simple are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
a Demand Adjuster
multiplied by
the Demand Rate from Section II.A.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible Priority Firm Power (PFF) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

Cited in Pacific Northwest Generating v. DOE, No 05-75638 archived on December 17, 2008

Note: The Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up GRSP from the FY 2002-2006 rate period will continue into the beginning of FY 2007. See Appendix B.

C. ACTUAL PARTIAL SERVICE PRODUCT - COMPLEX

Purchases of the Core Subscription Actual Partial Service Product – Complex are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
a Demand Adjuster
multiplied by
the Demand Rate from Section II.A.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Excess Factoring Charges	II.H
Flexible Priority Firm Power (PF) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Note: The Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up GRSP from the FY 2002-2006 rate period will continue into the beginning of FY 2007. See Appendix B.

D. BLOCK PRODUCT

Purchases of the Core Subscription Block Product are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
the Demand Rate from Section II.A.

Cited in Pacific Northwest Generating v. DOE, No. 05-75038 archived on December 17, 2008

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible Priority Firm Power (PFF) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

Cited in Pacific Northwest Generating v. DOE, No 05-75638 archived on December 17, 2008

Note: The Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up GRSP from the FY 2002-2006 rate period will continue into the beginning of FY 2007. See Appendix B.

E. BLOCK PRODUCT WITH FACTORING

Purchases of the Core Subscription Block Product with Factoring are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
a Demand Adjuster
multiplied by
the Demand Rate from Section II.A.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Excess Factoring Charges	II.H
Flexible Priority Firm Power (PF) Rate Option	II.J
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Note: The Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up GRSP from the FY 2002-2006 rate period will continue into the beginning of FY 2007. See Appendix B.

F. BLOCK PRODUCT WITH SHAPING CAPACITY

Purchases of the Core Subscription Block Product with Shaping Capacity are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
the Demand Rate from Section II.A.

Cited in Pacific Northwest Generating v. DOE, No. 05-75038 archived on December 17, 2008

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible Priority Firm Power (PFF) Rate Option	II.J
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

Cited in Pacific Northwest Generating v. DOE, No 05-75638 archived on December 17, 2008

Note: The Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up GRSP from the FY 2002-2006 rate period will continue into the beginning of FY 2007. See Appendix B.

G. SLICE PRODUCT

Purchases of the Subscription Slice Product are limited to Public Preference Customers and are subject to the charges specified below.

1. Slice Product Charge

The charge for the Slice Product will be:
the elected Slice Percentage expressed as a decimal (.01 = 1%)
multiplied by
100
multiplied by
the Slice Rate in Section II.D.

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Low Density Discount	II.L
Slice True-Up Adjustment	II.N
Unauthorized Increase Charge	II.Q

Note: The Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up GRSP from the FY 2002-2006 rate period will continue into the beginning of FY 2007. See Appendix B.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

H. PRIORITY FIRM EXCHANGE POWER

This PF Exchange rate applies to sales under the Residential Exchange Program.

1. Priority Firm Exchange Power Charges

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Billing Demand, (which is calculated by applying the load factor, determined as specified in the Residential Exchange Program agreement, to the Billing Energy for each billing period)
multiplied by
the Demand Rate from Section III.A.

Cited in Pacific Northwest Generating v. DOE, No. 05-75038 archived on December 17, 2008

1.2 Energy Charge

The monthly charge for energy will be:
the Purchaser's Billing Energy, (which is the energy associated with the utility's qualifying residential and small farm load for each billing period computed in accordance with the provisions of the Purchaser's Residential Exchange Program agreement)
multiplied by
the Energy Rate from Section III.B.1.

1.3 Load Variance Charge

No additional charge.

2. Transmission Charges

Customers purchasing under this rate schedule are charged for transmission services under the Network Transmission (NT) rate schedule or its successor.

Customers purchasing under this rate schedule are charged for Load Regulation under the applicable charge established by the Transmission Business Line (TBL) or its successor.

3. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Low Density Discount	II.L

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Note: The Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up GRSP from the FY 2002-2006 rate period will continue into the beginning of FY 2007. See Appendix B.

SECTION V. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule, except for the exchange product listed under Section IV.H.

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

SCHEDULE NR-07
NEW RESOURCE FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of Firm Power to be used within the PNW. New Resource Firm Power (NR) is available to IOUs under net requirements contracts for resale to ultimate consumers, for direct consumption, and for Construction, Test and Start-Up, and Station Service. NR also is available to any public body, cooperative, or Federal agency to the extent such power is needed to serve any New Large Single Load (NLSL), as defined by the Northwest Power Act. That portion of the utility's load placed on BPA that is attributable to the NLSL will be billed under this rate schedule.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Rates in this schedule apply from October 1, 2006, through September 30, 2009, for purchasers of New Resource Firm Power. Products available under this rate schedule are defined in BPA's 2007 General Rate Schedule Provisions (2007 GRSPs).

This rate schedule supersedes the NR-02 rate schedule, which went into effect October 1, 2001. Sales under the NR-07 rate schedule are subject to BPA's 2007 GRSPs and billing process.

SECTION II. RATES TABLES

The rates in this section apply to NR products.

A. DEMAND RATE

1. Monthly Demand Rate for FY 2007 through FY 2009

1.1 Applicability

These rates apply to eligible customers purchasing power.

1.2 Rate Table

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Applicable Months	*Rate*
January	$1.85 per kW
February	$1.88 per kW
March	$1.75 per kW
April	$1.64 per kW
May	$1.36 per kW
June	$1.25 per kW
July	$1.53 per kW
August	$1.79 per kW
September	$1.85 per kW
October	$1.94 per kW
November	$2.08 per kW
December	$2.18 per kW

B. ENERGY RATE

1. Monthly Energy Rates for FY 2007 through FY 2009

These rates apply to eligible customers purchasing power under this rate schedule.

1.1 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	87.41 mills/kWh	73.92 mills/kWh
February	87.61 mills/kWh	77.45 mills/kWh
March	84.04 mills/kWh	74.23 mills/kWh
April	69.72 mills/kWh	59.96 mills/kWh
May	61.74 mills/kWh	52.56 mills/kWh
June	60.87 mills/kWh	46.22 mills/kWh
July	73.18 mills/kWh	60.71 mills/kWh
August	80.76 mills/kWh	69.29 mills/kWh
September	84.00 mills/kWh	75.06 mills/kWh
October	78.85 mills/kWh	68.12 mills/kWh
November	93.17 mills/kWh	76.88 mills/kWh
December	97.76 mills/kWh	81.00 mills/kWh

Cited in Pacific Northwest Generating v. DOE
No. 05-75638 archived on December 17, 2008

C. LOAD VARIANCE RATE

The Load Variance Rate for FY 2007 through FY 2009 applies to customers purchasing this product consistent with Section III below. The rate for Load Variance is 0.47 mill/kWh.

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

SECTION III. BILLING FACTORS, AND ADJUSTMENTS FOR EACH NR PRODUCT

This rate schedule contains seven subsections, corresponding to the products to which this rate schedule applies. The following seven products are available to serve NLSLs, or other loads served at the NR-07 rate.

Section III.A. New Large Single Load

Section III.B. Full Service Product

Section III.C. Actual Partial Service Product - Simple

Section III.D. Actual Partial Service Product - Complex

Section III.E. Block Product

Section III.F. Block Product with Factoring

Section III.G. Block Product with Shaping Capacity

Cited in Pacific Northwest Generating v. DOE, No. 05-75828 archived on December 17, 2008

A. NEW LARGE SINGLE LOAD (NLSL) SERVICE PRODUCT

Purchases of New Resource Firm Power to serve a NLSL are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the NLSL's monthly Demand Entitlement as specified in the contract
multiplied by
the Demand Rate from Section II.A.

Cited in Pacific Northwest Generating v. DOE, No. 05-1538 archived on December 17, 2008

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2), unless BPA and the Purchaser agree to bill based on a contract amount of energy.

(1) The NLSL's HLH Energy Entitlement as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) the NLSL's LLH Energy Entitlement as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the NLSL's Measured Energy for the billing period as specified in the contract
multiplied by
the Load Variance Rate from Section II.C.

If the customer is already paying the Load Variance Charge on the NLSL load through this or another rate schedule, this charge does not apply.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible New Resource Firm Power (NR) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

Cited in Pacific Northwest Generating v. DOE, No 05-75638 archived on December 17, 2008

Note: The Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up GRSP from the FY 2002-2006 rate period will continue into the beginning of FY 2007. See Appendix B.

B. FULL SERVICE PRODUCT

Purchases of the Core Subscription Full Service Product are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Measured Demand on the GSP as specified in the contract
multiplied by
the Demand Rate from Section II.A.

Cited in Pacific Northwest Generating v. DOE, No. 95-75038 archived on December 17, 2008

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible New Resource Firm Power (NR) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

Cited in Pacific Northwest Generating v. DOE, No 05-75638 archived on December 17, 2008

Note: The Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up GRSP from the FY 2002-2006 rate period will continue into the beginning of FY 2007. See Appendix B.

C. ACTUAL PARTIAL SERVICE PRODUCT - SIMPLE

Purchases of the Core Subscription Actual Partial Service Product – Simple are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
a Demand Adjuster
multiplied by
the Demand Rate from Section II.A.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible New Resource Firm Power (NR) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

Cited in Pacific Northwest Generating v. DOE, No 05-75638 archived on December 17, 2008

Note: The Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up GRSP from the FY 2002-2006 rate period will continue into the beginning of FY 2007. See Appendix B.

D. ACTUAL PARTIAL SERVICE PRODUCT - COMPLEX

Purchases of the Core Subscription Actual Partial Service Product – Complex are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
a Demand Adjuster
multiplied by
the Demand Rate from Section II.A.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.E
Emergency NFB Surcharge	II.G
Excess Factoring Charges	II.H
Flexible New Resource Firm Power (NR) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Note: The Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up GRSP from the FY 2002-2006 rate period will continue into the beginning of FY 2007. See Appendix B.

E. BLOCK PRODUCT

Purchases of the Core Subscription Block Product are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
the Demand Rate from Section II.A.

Cited in Pacific Northwest Generating v. DOE, No. 95-75038 archived on December 17, 2008

1.2 Energy Charge

The total monthly charge for energy shall be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible New Resource Firm Power (NR) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

Cited in Pacific Northwest Generating v. DOE, No 05-75638 archived on December 17, 2008

Note: The Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up GRSP from the FY 2002-2006 rate period will continue into the beginning of FY 2007. See Appendix B.

F. BLOCK PRODUCT WITH FACTORING

Purchases of the Core Subscription Block Product with Factoring are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
a Demand Adjuster
multiplied by
the Demand Rate from Section II.A.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.E
Emergency NFB Surcharge	II.G
Excess Factoring Charges	II.H
Flexible New Resource Firm Power (NR) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Note: The Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up GRSP from the FY 2002-2006 rate period will continue into the beginning of FY 2007. See Appendix B.

G. BLOCK PRODUCT WITH SHAPING CAPACITY

Purchases of the Core Subscription Block Product with Shaping Capacity are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
the Demand Rate from Section II.A.

Cited in Pacific Northwest Generating v. DOE, No. 95-75038 archived on December 17, 2008

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 GRSPs. Relevant sections are identified below:

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible New Resource Firm Power (NR) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

Cited in Pacific Northwest Generating v. DOE, No 05-75638 archived on December 17, 2008

Note: The Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up GRSP from the FY 2002-2006 rate period will continue into the beginning of FY 2007. See Appendix B.

SECTION IV. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule unless BPA's PBL and the customer negotiate otherwise at time of sale. Regulation and Frequency Response may have to be purchased for NLSLs.

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

IP-07
INDUSTRIAL FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available to BPA's direct service industrial customers (DSI) for Firm Power to be used in their industrial operations. DSIs that are offered a requirements contract for which power deliveries begin on or after October 1, 2006 (2006 Contracts), are eligible to purchase under this rate schedule.

This rate schedule supersedes the IP-02 rate schedule, which went into effect October 1, 2001. Sales under the IP-07 rate schedule are subject to BPA's 2007 General Rate Schedule Provisions (2007 GRSPs) and billing process.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

SECTION II. RATES TABLES

The rates for the Industrial Firm Power (IP) product are identified below.

A. DEMAND RATE FOR ALL IP PRODUCTS

1. Flat Rate Demand for FY 2007 through 2009

1.1 Applicability

These monthly rates apply to eligible customers purchasing power.

1.2 Rate Table

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Applicable Months	*Rate*
January	$1.85 per kW
February	$1.88 per kW
March	$1.75 per kW
April	$1.64 per kW
May	$1.36 per kW
June	$1.25 per kW
July	$1.53 per kW
August	$1.79 per kW
September	$1.85 per kW
October	$1.94 per kW
November	$2.08 per kW
December	$2.18 per kW

B. ENERGY RATE

1. Monthly Energy Rates for FY 2007 through FY 2009

1.1 Applicability

These energy rates apply to eligible customers purchasing power.

1.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	49.99 mills/kWh	42.28 mills/kWh
February	50.10 mills/kWh	44.29 mills/kWh
March	48.06 mills/kWh	42.45 mills/kWh
April	39.87 mills/kWh	34.29 mills/kWh
May	35.31 mills/kWh	30.06 mills/kWh
June	34.81 mills/kWh	26.43 mills/kWh
July	41.85 mills/kWh	34.72 mills/kWh
August	46.18 mills/kWh	39.63 mills/kWh
September	48.04 mills/kWh	42.93 mills/kWh
October	45.09 mills/kWh	38.95 mills/kWh
November	53.28 mills/kWh	43.97 mills/kWh
December	55.90 mills/kWh	46.32 mills/kWh

Cited in Pacific Northwest Generating v. DOE
No. 05-75638 archived on December 17, 2008

C. LOAD VARIANCE RATE

The Load Variance Rate for FY 2007 through FY 2009 applies to customers purchasing this product consistent with Section III below. The rate for Load Variance is 0.47 mill/kWh.

SECTION III. BILLING FACTORS AND ADJUSTMENTS FOR THE IP PRODUCT

Only the firm take-or-pay Block Product is available under this rate schedule. Energy charges for the IP product would apply as specified in Section II.B.

1. Industrial Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
the Demand Rate from Section II.A.

Cited in Pacific Northwest Generating v. DOE, No. 95-75038 archived on December 17, 2008

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 GRSPs. Relevant sections are identified below:

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.E
Emergency NFB Surcharge	II.G
Green Energy Premium	II.K
Supplemental Contingency Reserves Adjustment	II.O
Unauthorized Increase Charge	II.Q

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Note: The Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up GRSP from the FY 2002-2006 rate period will continue into the beginning of FY 2007. See Appendix B.

SECTION IV. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule unless BPA's PBL and the customer negotiate otherwise at time of sale.

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

SCHEDULE FPS-07
FIRM POWER PRODUCTS AND SERVICES

SECTION I. AVAILABILITY

This rate schedule 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 during the period beginning October 1, 2006, and ending September 30, 2009.

Products and services available under this rate schedule are described in the 2007 General Rate Schedule Provisions (2007 GRSPs). BPA is not obligated to sell even if sales will not displace PF/NR/IP sales. Sales under the FPS-07 rate schedule are subject to the applicable provisions of BPA's 2007 GRSPs. Transmission service over Federal Columbia River Transmission System facilities shall be charged under the applicable transmission rate schedule. Ancillary services shall be available under, or at charges consistent with, the Ancillary Products and Services (APS) rate schedule for transmission.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

This rate schedule supersedes the Firm Power Products and Services (FPS-96R) rate schedule. Rates under contracts that contain charges that escalate based on rates listed in this rate schedule shall include applicable transmission charges. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's 2007 GRSPs and billing process.

SECTION II. RATES, BILLING FACTORS, AND ADJUSTMENTS

For each product, the rate(s) for each product along with the associated billing factor(s) are identified below. Applicable adjustments, charges, and special rate provisions are listed for each product. This rate schedule contains four subsections, corresponding to the products offered under this rate schedule:

Section II.A. Firm Power and Capacity Without Energy.

Section II.B. Supplemental Control Area Services.

Section II.C. Shaping Services.

Section II.D. Reservation and Rights to Change Services.

A. FIRM POWER AND CAPACITY WITHOUT ENERGY

1. Rates and Billing Factors

1.1 Contract Rate

The demand charge in the Contract Rate applies to purchases of a firm capacity with no energy return product exclusively, that is, a firm power sale product. Firm capacity with energy return (Capacity Without Energy) is available under the FPS-07 rate schedule at the prices identified in Section II.A.1.3. Contracts entered into, on, or before September 30, 1996, that refer to the demand charge in the Contract Rate section of the then applicable surplus power schedule for pricing this product will be priced under Section II.A.1.3.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

1.1.1 Demand Charge

The charge for monthly demand shall be the applicable Demand rate for that month *multiplied by* the monthly Contract Demand unless otherwise agreed by BPA and the Purchaser.

Applicable Months	*Rate*
Jan	$1.85 per kW
Feb	$1.88 per kW
Mar	$1.75 per kW
Apr	$1.64 per kW
May	$1.36 per kW
Jun	$1.25 per kW
Jul	$1.53 per kW
Aug	$1.79 per kW
Sep	$1.85 per kW
Oct	$1.94 per kW
Nov	$2.08 per kW
Dec	$2.18 per kW

1.1.2 Demand Charge – Capacity Without Energy Sales

See Section II.A.1.3 for pricing.

1.1.3 Energy Charge

The total monthly charge for energy shall be the sum of (1) and (2):

(1) the applicable HLH rate for that month, *multiplied by* the Purchaser's HLH Contract Energy unless otherwise agreed by BPA and the Purchaser; and

(2) the applicable LLH rate for that month, *multiplied by* the Purchaser's LLH Contract Energy unless otherwise agreed by BPA and the Purchaser.

Applicable Months	*HLH Rate*	*LLH Rate*
Jan	59.13 mills/kWh	50.01 mills/kWh
Feb	59.27 mills/kWh	52.39 mills/kWh
Mar	56.85 mills/kWh	50.21 mills/kWh
Apr	47.16 mills/kWh	40.56 mills/kWh
May	41.76 mills/kWh	35.55 mills/kWh
Jun	41.17 mills/kWh	31.27 mills/kWh
Jul	49.51 mills/kWh	41.07 mills/kWh
Aug	54.63 mills/kWh	46.87 mills/kWh
Sep	56.83 mills/kWh	50.78 mills/kWh
Oct	53.34 mills/kWh	46.08 mills/kWh
Nov	63.03 mills/kWh	52.01 mills/kWh
Dec	66.13 mills/kWh	54.79 mills/kWh

Cited in Pacific Northwest Generating v. DOE No. 05-75636 archived on December 17, 2008

1.2 Flexible Rate

Demand and/or energy charges may be specified at a higher or lower average rate as mutually agreed by BPA and the Purchaser. Billing factors shall be Contract Demand and Contract Energy unless otherwise agreed by BPA and the Purchaser.

1.3 Capacity Without Energy

1.3.1 Flexible Rate

For sales not covered by Section II.A.1.3.2 the rate(s) for Capacity Without Energy sales shall be as mutually agreed by BPA and the Purchaser.

1.3.2 Posted Rate

The posted rates shall be applied to contracts entered into, on, or before September 30, 1996, that include Capacity Without Energy provisions where payment shall be at the demand charge associated with the Contract Rate of the then applicable surplus power rate schedule. These rates may also be applied to contracts for Capacity Without Energy entered into, on, or after June 1, 2000. For sales pursuant to such contracts the monthly charge for Capacity Without Energy shall be the applicable rate for that month, *multiplied by* the Purchaser's monthly Contract Demand associated with the purchase of Capacity Without Energy.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Applicable Months	***Rate***
Jan	$7.06 per kW
Feb	$7.08 per kW
Mar	$6.79 per kW
Apr	$5.63 per kW
May	$4.99 per kW
Jun	$4.92 per kW
Jul	$5.92 per kW
Aug	$6.53 per kW
Sep	$6.79 per kW
Oct	$6.37 per kW
Nov	$7.53 per kW
Dec	$7.90 per kW

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Cost Contributions	II.C
Unauthorized Increase Charge	II.Q
West-Wide Price Cap of FPS Sales	II.R

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

B. SUPPLEMENTAL CONTROL AREA SERVICES

1. Rates and Billing Factors

The charge for Supplemental Control Area Services shall be the applicable rate(s) times the applicable billing factor(s), pursuant to the agreement between BPA and the Purchaser.

The rate(s) and billing factor(s) for Supplemental Control Area Services shall be as established by BPA or as mutually agreed by BPA and the Purchaser.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

Cited in Pacific Northwest Generating v. DOE, No. 05-75628 archived on December 17, 2008

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Cost Contributions	II.C
Unauthorized Increase Charge	II.Q

C. SHAPING SERVICES

1. Rates and Billing Factors

The charge for Shaping Services shall be the applicable rate(s) times the applicable billing factor(s), pursuant to the agreement between BPA and the Purchaser.

The rate(s) and billing factor(s) for use of Shaping Services shall be as established by BPA or as mutually agreed by BPA and the Purchaser.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Cost Contributions	II.C
Unauthorized Increase Charge	II.Q

D. RESERVATION AND RIGHTS TO CHANGE SERVICES

1. Rates and Billing Factors

The charge for Reservation and Rights to Change Services shall be the applicable rate(s) times the applicable billing factor(s), pursuant to the agreement between BPA and the Purchaser.

The rate(s) and billing factor(s) for Reservation and Rights to Change Services shall be as established by BPA or mutually agreed by BPA and the Purchaser.

2. Adjustments, Charges, and Special Rate Provisions

There are no additional adjustments, charges, or special rate provisions for the Reservation and Rights to Change Services.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

GTA
GENERAL TRANSFER AGREEMENT DELIVERY CHARGE

Customers who purchase Federal power that is delivered over non-Federal low voltage transmission facilities shall pay a GTA Delivery Charge. The GTA Delivery Charge is a BPA Power Business Line charge for low voltage delivery service of Federal power provided under General Transfer Agreements (GTAs) and other non-Federal transmission service agreements.

For the period from October 1, 2006, through September 30, 2007, the rate will be as follows:

1. Rate

$1.119 per kilowatt per month

2. Billing Factor

The monthly Billing Factor for the GTA Delivery rate shall 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.

At those 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.

Cited in Pacific Northwest Generating v. DOE, No. 05-75608 archived on December 17, 2008

For the period from October 1, 2007, through September 30, 2009, the rate will be adjusted to the most current transmission Utility Delivery rate under the Transmission Business Line's (TBL) posted Delivery Charge schedule in the approved Transmission & Ancillary Service Rate Schedules.

1. Rate

The rate established in TBL's FY 2008-2009 rate proceeding.

2. Billing Factor

The billing factor established in TBL's FY 2008-2009 rate proceeding.

(*Monthly Transmission Peak Load* is the peak loading on the Federal transmission system during any hour of the designated billing month, determined by the largest hourly integrated demand produced from the sum of Federal and non-Federal generating plants in BPA's Control Area and metered flow into BPA's Control Area.)

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

BPA'S 2007

GENERAL RATE SCHEDULE PROVISIONS (GRSPs)

FOR POWER RATES

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

BONNEVILLE
POWER ADMINISTRATION

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

INDEX

2007 GENERAL RATE SCHEDULE PROVISIONS

Subject **Page**

SECTION I: ADOPTION OF REVISED RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

A. Approval of Rates 71
B. General Provisions 71
C. Payment Provisions 71
D. Notices 72
E. Provision for Reassignment of Surplus Transmission Capacity 72

SECTION II: ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Cited in Pacific Northwest Generating v. DOE, No. 05-73638 archived on December 17, 2008

A. Conservation Rate Credit (CRC) 73
B. Conservation Surcharge 77
C. Cost Contributions 78
D. Cost Recovery Adjustment Clause (CRAC) 78
E. Demand Adjuster 88
F. Dividend Distribution Clause (DDC) 89
G. Emergency NFB Surcharge 95
H. Excess Factoring Charges 104
I. Flexible New Resource Firm Power (NR) Rate Option 107
J. Flexible Priority Firm Power (PF) Rate Option 107
K. Green Energy Premium 108
L. Low Density Discount (LDD) 109
M. Rate Melding 114
N. Slice True-Up Adjustment 114
O. Supplemental Contingency Reserves Adjustment (SCRA) 117
P. Targeted Adjustment Charge (TAC) 118
Q. Unauthorized Increase Charge (UAI Charge) 121
R. West-wide Price Cap of FPS Sales 122

SECTION III: DEFINITIONS

A. Power Products and Services Offered By the Power Business Line of BPA 123
1. Actual Partial Service Product – Simple/Complex 123
2. Block Product 123
3. Block Product with Factoring 123
4. Block Product with Shaping Capacity 123
5. Capacity Without Energy 123
6. Construction, Test and Start-Up and Station Service 124
7. Core Subscription Products 124
8. Customer System Peak (CSP) 125

SECTION III: DEFINITIONS (Continued)

9. Full Service Product 125
10. Industrial Firm Power (IP) 125
11. Load Variance 125
12. New Resource Firm Power (NR) 125
13. Priority Firm Power (PF) 126
14. Regulation and Frequency Response 126
15. Residential Exchange Program Power 126
16. Slice Product 126

B. Definition of Rate Schedule Terms 128
1. Annual Billing Cycle 128
2. Billing Demand 128
3. Billing Energy 128
4. California Independent System Operator (CAISO) 128
5. California Independent System Operator (CAISO) Spinning Reserve Capacity 128
6. California Independent System Operator (CAISO) Supplemental Energy 128
7. Contract Demand 129
8. Contract Energy 129
9. Control Area 129
10. Delivering Party 129
11. Demand Entitlement 129
12. Discount Period 129
13. Dow Jones Mid-C Indexes (DJ Mid-C Indexes) 129
14. Electric Power 129
15. Energy Entitlement 130
16. Federal System 130
17. Firm Power (PF-07, IP-07, NR-07) 130
18. Full Service Customer 130
19. Generation System Peak (GSP) 130
20. Heavy Load Hours (HLH) 130
21. Inventory Augmentation (or Inventory Solution) 131
22. Light Load Hour (LLH) 131
23. Measured Demand 131
24. Measured Energy 132
25. Metered Demand 132
26. Metered Energy 132
27. Monthly Federal System Peak Load 133
28. Net Billing Capacity Deficiency 133
29. NP15 133
30. NW1 (COB) 133
31. NW3 (NOB) 133
32. Partial Service Customer 133
33. Point of Delivery (POD) 133

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

SECTION III: DEFINITIONS (Continued)

34. Point of Integration (POI) 133
35. Point of Interconnection (POI) 134
36. Points of Metering (POM) 134
37. Pre-Subscription Contract 134
38. Purchaser 134
39. Receiving Party 134
40. Retail Access 134
41. Scheduled Demand 134
42. Scheduled Energy 135
43. Slice Revenue Requirement 135
44. Subscription 135
45. Subscription Contract 135
46. Total Plant Load (TPL) 135
47. Total Retail Load (TRL) 135
48. Utility Distribution Company (UDC) 136

Appendix A. 2002 Slice Rate Methodology 137
Table 1 – Slice Product Costing and True-Up Table 145

Appendix B Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up..... 147

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

2007 GENERAL RATE SCHEDULE PROVISIONS

SECTION I. ADOPTION OF REVISED RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

A. Approval of Rates

These 2007 Wholesale Power Rate Schedules and General Rate Schedule Provisions (2007 GRSPs) shall become effective upon interim approval or upon final confirmation and approval by the Federal Energy Regulatory Commission (FERC). BPA has requested that FERC make these rates and 2007 GRSPs effective on October 1, 2006. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

Cited in Pacific Northwest Generating v. DOE No. 05-75038 archived on December 17, 2008

B. General Provisions

These 2007 Wholesale Power Rate Schedules and the 2007 GRSPs associated with these schedules supersede BPA's 2002 rate schedules (which became effective October 1, 2001) to the extent stated in the Availability Section of each rate schedule, and the FPS-96R which became effective October 1, 1996. These schedules and the 2007 GRSPs shall be applicable to all BPA contracts, including contracts executed both prior to, and subsequent to, enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). All sales under these rate schedules are subject to the following acts as amended: The Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Transmission System Act (P.L. 93-454), the Northwest Power Act (P.L. 96-501), and the Energy Policy Act of 1992 (P.L. 102-486).

These 2007 rate schedules do not supersede any previously established rate schedule which is required, by agreement, to remain in effect.

If a provision in an executed agreement is in conflict with a provision contained herein, the former shall prevail.

C. Payment Provisions

Payment must be received by the 20th day after the issue date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or Federal holiday, the Due Date is the next business day. A late payment charge shall be applied each day to any unpaid balance. The late payment charge is calculated by dividing the applicable "Prime Rate" (reported in the "Money Rates" Section of the Wall Street Journal) plus 4 percent; by 365. The applicable "Prime Rate" shall be the rate reported on the first day of the month in which payment is received. The customer shall pay by electronic funds transfer using BPA's established procedures.

D. Notices

For the purpose of determining elapsed time from receipt of a notice applicable to rate schedule and GRSPs administration, a notice shall be deemed to have been received at 0000 hours on the first calendar day following actual receipt of the notice.

E. Provision for Reassignment of Surplus Transmission Capacity

PBL may reassign transmission capacity that it has reserved for its own use at a price not to exceed the highest of: (1) the original transmission rate paid by PBL; or (2) the applicable transmission provider's maximum stated firm transmission rate on file at the time of the transmission reassignment. Except for the price, the terms and conditions under which the reassignment is made shall be the terms and conditions governing the original grant by the transmission provider. Transmission capacity may only be reassigned to a customer eligible to take service under the transmission provider's open access transmission tariff or other transmission rate schedules.

Cited in Pacific Northwest Generating v. DOE
No. 05-75638 archived on December 17, 2008

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. Conservation Rate Credit (CRC)

1. Purpose and General Overview of the of the Conservation Rate Credit

(a) The Conservation Rate Credit (CRC) is available to customers purchasing under the PF, IP and NR rate schedules that take action to achieve cost-effective conservation and renewable resource development in the region.

(b) Each customer will be eligible for the CRC rate credit, set at 0.5 mills/kWh, applied to their eligible loads. The CRC rate credit is included in the posted rates for Subscription power purchases. The 0.5 mills/kWh CRC rate credit will be incorporated into the calculation of the Investor-Owned Utilities Residential Exchange Program Settlement (REP Settlement) consistent with those contracts.

Cited in Pacific Northwest Generating v. DOE, No. 05-75038 archived on December 17, 2008

(c) Individual participants in the CRC rate credit will make investments in cost-effective conservation and qualifying renewable resource development in the region, in a dollar amount equal to their eligible BPA loads times 0.5 mills/kWh.

(d) BPA will determine and publish lists of eligible measures and specific activities in the most current CRC Implementation Manual that satisfy customer obligations when implemented.

(e) Published lists will include the specific dollar amount of eligibility credited for each qualifying measure or activity.

(f) Each customer participating in the CRC program will administer its CRC activities pursuant to the most current CRC Implementation Manual.

2. Calculation of the Conservation Rate Credit

(a) Applicable Rate Schedules, Contracts, and Settlement Benefits. The CRC rate credit applies to loads served under the following:

(1) Priority Firm Power (PF-07) rate schedule.

(2) Slice product under the PF-07 rate schedule

(3) New Resource Firm Power (NR-07) rate schedule.

(4) Industrial Firm (IP-07) rate schedule.

(5) Benefits provided, as a cash payment in the REP Settlement, will also be eligible for the CRC, subject to the terms of such settlement.

(b) Sources of CRC Qualifying Load Data.

(1) Qualifying loads for customers purchasing Full, Partial Requirements, or Block Subscription products will be equal to the total of their respective annual forecasted average net requirements established in the FY 2007-09 rate case.

(2) Loads for individual Slice customer will be calculated using their individual slice percentage times 7070 aMW.

(3) For IOUs under the REP Settlement, BPA will provide the CRC according to the terms of those settlement contracts.

Cited in Pacific Northwest Generating v. DOE, No. 05-73638 archived on December 17, 2008

(c) Calculation of the Monthly and Annual CRC Eligibility

(1) For Full and Partial Requirements, Block, and Slice customers, BPA determines each customer's average monthly load by dividing the total forecast load for the three-year 2007 through 2009 rate period determined in section 2 (b) by 36. Then BPA will multiply each customer's average monthly load by 0.5 mills/kWh (*i.e.*, $0.0005) and rounded to the nearest whole dollar. This number is equal to the customer's rounded monthly rate credit

(2) The customer's annual CRC eligibility will be determined by multiplying the rounded monthly CRC by 12.

(d) Applications of the Monthly Rate Credit.

(1) The monthly rate credit will be posted, as a deduction, on the customer's monthly total power bill.

(2) The monthly rate credit will be subtracted after BPA has determined all other charges and credits on the participating customer's power bill.

(3) BPA will provide the monthly rate credit even in those months when the amount is larger than the customer's total power bill amount.

(4) For customers showing an annual net billing capacity deficiency, BPA may disburse the customer's monthly rate credit in the form

of a monthly check in the same amount as the customers monthly CRC.

(5) For the IOU residential exchange program settlement (REP Settlement) customers, BPA will disburse the monthly rate credit according to the terms of their current settlement contracts.

(e) Notification.

(1) Prior to the beginning of the early start of the CRC (January 1, 2006), the BPA Power Business Line Customer Account Executives will send each participating customer a letter documenting the forecasted qualifying loads and monthly rate credit amounts for the duration of the FY 2007-2009 Rate Period.

Cited in Pacific Northwest Generating v. DOE, No. 05-75038, archived on December 17, 2008

3. Reporting and Review of Individual Customers' CRC Activity

(a) Customers submitting progress reports documenting cumulative qualifying expenditures of less than 50 percent of the cumulative monthly rate credits after the second semi-annual report (*i.e.*, October 31, 2007) must prepare an action plan documenting planned spending for the remainder of the rate period that show how they will increase their CRC activities to acceptable levels.

(b) Customers submitting progress reports documenting cumulative qualifying expenditures of less than 75 percent of the cumulative monthly rate credits after the third semi-annual report (*i.e.*, April 30, 2008) may become ineligible to receive the CRC rate credit. If determined ineligible, BPA will suspend the customer's CRC rate credit on their power bill for the remainder of the rate period.

(1) BPA will provide the customer notice of removal of the CRC monthly rate credit from the customer's bill no later than June 30, 2008.

(2) BPA will remove the CRC monthly rate credit from the customer's bill for the first billing period beginning 61 calendar days or more from the date of the BPA notice of removal.

(3) Customer eligibility for the CRC will end on the last day of the first billing period ending 60 calendar days or more BPA provides a customer notice of removal of the CRC monthly rate credit.

(4) Customers ineligible to receive the CRC will be required to report to the BPA CRC manager total CRC qualifying expenditures

within 90 calendar days of receiving notice from BPA determining their ineligibility..

(A) If total reported CRC qualifying expenditures are less than total accumulated monthly rate credits, computed from the beginning of the rate period to the last day of customer eligibility, the customer will be required to:

i. report additional qualifying expenditures within 120 calendar days of receiving a notice of ineligibility;

OR

ii. reimburse BPA for the difference between total reported qualifying expenditures and total accumulated monthly rate credits within 120 calendar days of receiving a notice of ineligibility.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

(c) Customers may elect not to receive the CRC monthly rate credit by giving BPA 60 calendar days written notice of their intent to stop participation.

(1) BPA will remove the CRC monthly rate credit from a customer's bill for the first billing period beginning 61 calendar days or more after BPA receipt of the customers notice.

(2) Customer eligibility for the CRC monthly rate credit will end on the last day of the billing period ending 60 calendar days or more after BPA receipt of the customers notice.

(3) Customers electing not to receive the CRC monthly rate credit will be required to report to BPA total CRC qualifying expenditures within 90 calendar days of BPA receipt of the customers' notice.

(A) If total reported CRC qualifying expenditures are less than total accumulated monthly rate credits, computed from the beginning of the rate period to the end of customer eligibility, the customer will be required to:

i. report additional qualifying expenditures within 120 calendar days of BPA receipt of customers' notice.

OR

ii. reimburse BPA for the difference between total reported qualifying expenditures and total accumulated monthly rate credits, within 120 calendar days of BPA receipt of customer's notice.

(d) Final Reconciliation Reports

(1) Within 30 calendar days of the end of the rate period (October 31, 2009), each customer shall submit a final reconciliation report summarizing the customer's total CRC qualifying expenditures and total CRC accumulated monthly rate credits, for the rate period to the BPA CRC manager for review.

Cited in Pacific Northwest Generating v. DOE
No. 05-75638 archived on December 17, 2008

(2) If a participating customer's final reconciliation report shows that the total CRC accumulated monthly rate credit received from BPA exceeds the customer's total CRC qualifying expenditures, the customer may take an additional month (for a total of two months after the end of the rate period) to make the necessary additional qualifying expenditures and prepare a revised final reconciliation report.

(3) The final report is due to BPA within two months of the end of the rate period (December 1, 2009). If the customer's total CRC qualifying expenditures still do not equal or exceed their total CRC accumulated monthly rate credit, the customer must reimburse the difference to BPA on or before January 31, 2010.

(4) No reimbursements are required of any participating customer whose total CRC qualifying expenditures over the rate period are equal to or exceed the total CRC accumulated monthly rate credit received from BPA.

(5) BPA will not assess interest on any reimbursement paid within the two-month window. However, any payment received after the due date (December 1, 2009) shall be subject to a late payment charge as described in the customer's Subscription contract.

B. Conservation Surcharge

The Conservation Surcharge, where implemented, shall be applied in accordance with relevant provisions of the Northwest Power Act, BPA's current Conservation Surcharge policy, and the customer's power sales contract with BPA. The Conservation Surcharge would apply to PF-07 (including Slice purchasers), and NR-07 rate schedules.

C. Cost Contributions

BPA has made the following resource cost determinations:

1. The forecast average cost of resources available to BPA under average water conditions is 22.43 mills/kWh.

2. The approximate cost contribution of different resource categories to each rate schedule is as shown in Table A:

Table A

Rate Schedule	*Resource Cost Contribution*		
	Federal Base System	**Exchange**	**New Resources**
PF	77.05%	22.95%	0%
IP	0%	89.33%	10.67%
NR	0%	89.33%	10.67%

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

D. Cost Recovery Adjustment Clause

The CRAC is an upward adjustment to the FY 2007-2009 energy base rates given in the Record of Decision (ROD). It is calculated by a formula that compares PBL Accumulated Modified Net Revenues (AMNR) (as defined by the CRAC) to three annual Thresholds, and places caps on the amount of revenue that can be generated each year.

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

- PF-07 [Preference (excluding the PF Slice Product) and PF Exchange Power];
- 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 under the Investor Owned Utility Residential Exchange Program Settlement benefits (IOU REP Settlement benefits); and
- the benefits provided to Direct Service Industry (DSI) customers under the FY 2005 DSI Service ROD.

The CRAC does not apply to:

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

- Demand Sales (If a triggering event due to the NFB Adjustment increases the total amount of revenue to be collected through the CRAC above the cap of $300 million, then BPA will recover the revenues in excess of the cap through an increase to all demand, energy, and Load Variance Rates proportionately.)

1. Calculations for the Cost Recovery Adjustment Clause

Prior to the beginning of each fiscal year of the rate period (*i.e.,* FY 2007-2009), BPA will forecast the current year's end-of-year AMNR. If the forecasted AMNR is less than the defined CRAC Threshold for that fiscal year, the CRAC will trigger, and a rate increase will go into effect beginning in October of the upcoming fiscal year.

Cited in Pacific Northwest Generating v. DOE, No. 05-75828 archived on December 17, 2008

(a) Calculating the CRAC Amount

CRAC Amount is the lower of:

CRAC Threshold minus forecasted AMNR;

or

The Maximum CRAC Recovery Amount (Cap) for each year, shown in Table B below.

Table B: CRAC Annual Thresholds and Caps
[Dollars in Millions]

AMNR Calculated at end of Fiscal Year	CRAC Applied to Fiscal Year	CRAC Threshold*	Approx. Threshold as Measured in PBL Reserves	Maximum CRAC Recovery Amount (Cap)**
2006	2007	-$151	$750	$300
2007	2008	-$53	$750	$300
2008	2009	-$48	$750	$300

* As measured by AMNR.
** 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 FYs 2006, 2007, and 2008.

Where CRAC Amount is the additional net revenue that an increase in rates, due to the CRAC, is intended to generate in the next fiscal year.

Where CRAC Threshold is the "trigger point" for invoking a rate increase under the CRAC. The CRAC Threshold is specified for the end of FYs 2006, 2007, and 2008, in Table B.

Where AMNR is generation function net revenues, as accumulated since 1999, at the end of each year for FY 2006 through FY 2008. The forecast of AMNR is used to determine if the CRAC Threshold has been reached, and if so, the required CRAC Amount to be collected. The forecast of AMNR through the end of each fiscal year will be calculated by determining the accumulated annual Modified Net Revenue (MNR) during the rate period.

Where the MNR for any given fiscal year is defined as generation function accrued revenues less accrued expenses (in accordance with Generally Accepted Accounting Principles) with three exceptions:

Cited in Pacific Northwest Generating v. DOE, No. 05-75638; archived on December 17, 2008

(1) The calculation of MNR will exclude the impact of adopting Financial Accounting Standard 133, Accounting for Derivative Instruments and Hedging Activities (including supplemental standards issued by FASB and interpretations regarding derivatives and hedging activities), and actual Energy Northwest (EN) debt service. (BPA has adopted FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities as amended by FASB Statements 137, 138, and 149 and interpreted by Derivatives Implementation Group issues (together, "FAS 133")* as of October 1, 2000.)

(2) The calculation of MNR will include forecasted EN debt service identified in the WP-07 Final Studies.

(3) The forecast of MNR will be based on actual generation function revenues and expenses for the first three quarters of the year and forecasted results for the remainder of the year, and will include revenues and expenses that are associated with the production, acquisition, marketing, and conservation of electric power. The transmission function accrued revenues and expenses are excluded. The MNR includes impacts on forecasted revenues, positive or negative, from contractual true-up pursuant to the Slice Agreement.

Where Maximum CRAC Recovery Amount (Cap) is the maximum annual amount that is allowed to be recovered through the CRAC.

(b) Converting the CRAC Amount to a Percentage

Once the CRAC Amount is determined, that amount will be converted to the CRAC Percentage. The additional CRAC revenue will be generated by

applying this percentage to the applicable power rates and benefits in the following way:

(1) The CRAC Percentage is the percentage increase applied to customers' HLH and LLH energy and Load Variance Sales under the firm power rate schedules subject to the CRAC.

(2) The CRAC Amount will be applied to the energy rate components of the lowest cost-based power rate schedule (the PF Block Product as defined by the IOU REP Settlement) used to calculate the annual IOU REP Settlement benefits. This may change the IOU REP Settlement benefits, depending on the effects of the cap and floor. This change, if any, will be factored into the calculation of the CRAC Percentage.

(3) The CRAC Amount will be applied to the energy rate components of the PF Block Rate used to calculate the annual DSI service benefits. The calculation of the CRAC percentage will not include any anticipated effect on the DSI service benefits.

Cited in Pacific Northwest Generating v. DOE
No. 05-75638 archived on December 17, 2008

(c) Accounting for IOU Impact on the CRAC Percentage

The IOU REP Settlement benefits are constrained by a cap and floor. The CRAC Amount that will be collected by reducing the IOU REP Settlement benefits is calculated first before calculating the portion of the CRAC Amount that needs to be collected from the PF products subject to the CRAC. First, it is assumed that the CRAC Amount can be recovered from both the IOU REP Settlement benefits and the CRAC-adjusted PF rates. A check is then performed to see whether the cap and floor constrains the portion of the CRAC Amount that can be collected via reductions in the IOU REP Settlement benefits. The PF portion of the CRAC Amount is the CRAC Amount less the portion of the CRAC Amount that can be collected from the IOU REP Settlement benefits. The CRAC Percentage is calculated by dividing the PF CRAC Amount by the most current forecast of HLH, LLH, and Load Variance revenues from products subject to the CRAC.

The CRAC percentage will be the lowest percentage that, when applied to HLH and LLH energy and Load Variance, generates additional net revenue (additional PF revenue combined with possible reductions in IOU REP Settlement benefits) in the amount required by the CRAC formula.

For products subject to the CRAC, the CRAC percentage will be applied to HLH and LLH base energy rates and the Load Variance Rate for the twelve months beginning in October and ending the following September.

The IOU Settlement REP benefit and the DSI service benefit calculation will be adjusted if the benefits fall below the cap or rise above the floor.

2. Actions to Mitigate the CRAC

If PBL accumulated modified net revenues at the end of a fiscal year are within $150 million of the CRAC threshold for the subsequent year, BPA will prepare and post on its Web site an analysis for the causes of BPA's financial decline compared to the rate case plan, and propose a prioritized list of potential actions to avert or mitigate the need for a CRAC. BPA shall conduct a comment period on these actions to avert or reduce a potential CRAC rate adjustment by the following October.

Cited in Pacific Northwest Generating v. DOE, No. 05-75658 archived on December 17, 2008

3. CRAC Adjustment Timing

In August prior to beginning of each year of the rate period, the Administrator will determine whether the expected value of the AMNR forecast at the end of that fiscal year is below the CRAC Threshold. If the AMNR is forecasted to fall below the CRAC Threshold, the Administrator will propose, by the end of August, to assess a cost recovery adjustment to applicable rates for power deliveries beginning in October.

Customers will be notified, on or about September 1, of the percentage increase applicable to the base, if any, due to the CRAC. The rates used to calculate the customers' bills for the following October through September will reflect the CRAC increase.

(a) CRAC Notification Process

BPA shall use the following notification procedures:

(1) Financial Performance Status Reports

Each quarter, BPA shall post to its external website (www.bpa.gov), preliminary, unaudited, *year-to-date* aggregate financial results for the generation function, including AMNR.

For the 2nd and 3rd Quarter Review, BPA shall post to its external website (www.bpa.gov), the preliminary, unaudited *end-of-year* forecast of AMNR attributable to the generation function.

(2) Notice of CRAC Trigger

BPA shall complete a forecast of current fiscal end-of-year AMNR in August of each year. BPA shall notify all customers and rate case parties by the end of August, in each FYs 2006-2008 (prior to the beginning of the next fiscal year), if the expected value of AMNR is forecasted to fall below the CRAC Threshold for that fiscal year and, if so, the extent to which BPA intends to adjust rates due to the CRAC. Notification will be posted on BPA's website and will include the AMNR based on audited results, for the prior fiscal year, the forecast of end-of-year AMNR, the calculation of the Revenue Amount, and the forecast of the CRAC Percentage. The notice shall also describe the data and assumptions relied upon by BPA for the AMNR determination. Such data, assumptions, and documentation, if non-proprietary and/or non-privileged, shall be made available for review from BPA upon request.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

In early September of any year in which the AMNR is forecasted to fall below the CRAC Threshold, BPA staff shall conduct a workshop(s) to explain the AMNR forecast, the calculation of the CRAC Amount and the CRAC Percentage, and to demonstrate that the CRAC has been implemented in accordance with these GRSPs. The workshop will provide an opportunity for public comment.

The Administrator may elect at his discretion to reduce the CRAC rate adjustment. If the Administrator so elects, BPA will recalibrate the caps and the thresholds for the CRAC for later years to maintain the equivalent three-year PBL TPP of 92.6 percent based on then-current information. He shall then inform the customers of his decision during the workshops. The three-year TPP standard for reducing the FY 2007 CRAC is 92.6%, the two-year TPP standard for reducing the FY 2008 CRAC is 95.0%, and the one-year TPP standard for reducing the FY 2009 CRAC is 97.5%.

On or about September 30 of any fiscal year in which the AMNR is forecasted to fall below the CRAC Threshold, BPA will post to the BPA website the final calculation of the percentage adjustment to each product and the dollar adjustment to each benefit subject to the CRAC as described above. This will include any National Marine Fisheries Service [NMFS] Federal Columbia River Power System [FCRPS] Biological Opinion [BiOp] (NFB) adjustment to the CRAC calculation.

4. One-Time Adjustment of the CRAC Thresholds Due to Lower Enrollment in the Flexible PF Rate Program

In the WP-07 Final Studies, BPA included an estimate of $125 million of participation in the Flexible PF Rate Program using the Flexible PF rate option. The additional liquidity assumed by BPA to be available was included in the calculation of the base rates and in establishing the CRAC Thresholds to achieve a minimum three-year TPP of 92.6 percent. Since this source of liquidity is uncertain, BPA will reassess the final amount after August 25, 2006, and adjust the CRAC Thresholds to maintain the TPP of 92.6 percent if the final amount of enrollment in the Flexible PF Rate Program is less than that assumed in the Final Studies.

Cited in Pacific Northwest Generating v. DOE, No. 05-75628 archived on December 17, 2008

(1) Determining the actual enrollment in the Flexible PF Rate Program

The following conditions must be satisfied prior to August 26, 2006.

(a) The Customer and BPA have each signed a formal agreement (contract) establishing the Customer as a participant in the Flexible PF Rate Program for the duration of the FY 2007-2009 rate period.

(b) The customer has secured and provided to BPA a letter of credit, stand-by letter of credit, or other mutually agreed-to form of liquidity guarantee, with a financial institution providing BPA with the assurance of payment under the terms of the Flexible PF Rate Program.

(2) Adjusting the CRAC Thresholds for a Lower Enrollment Amount in the Flexible PF Rate Program

If a lower amount of Flexible PF revenue is available than was assumed in the WP-07 Final Studies, then the CRAC Thresholds will be adjusted upward to account for the lower amount, after this new amount is rounded down to the nearest $20 million. The CRAC Thresholds will be adjusted to the predetermined levels as specified in Table C.

Table C Adjusted CRAC Thresholds for Reduced Flexible PF Revenues [Dollars in Millions]						
Flexible PF Parti-cipation	Equiv. Amt. of Reserves	PBL Liquidity Reserves	CRAC Thresholds			
			Equiv. in Reserves	Thresholds in AMNR		
				2007	2008	2009
125.0	**86.3**	**88.7**	**750.0**	**-151.2**	**-52.9**	**48.2**
120.0	82.9	92.1	753.0	-148.2	-49.9	51.3
100.0	69.1	105.9	786.0	-118.2	-19.7	81.8
80.0	55.2	119.8	814.0	-87.2	11.7	113.3
60.0	41.4	133.6	832.0	-69.2	30.0	131.6
40.0	27.6	147.4	857.0	-44.2	55.7	156.8
20.0	13.8	161.2	877.0	-24.2	76.4	177.0
0.0	0.0	175.0	905.0	3.8	105.7	205.0

Cited in Pacific Northwest Generating v. DOE, No. 05-73638 archived on December 17, 2008

5. Contingent Recalculation of the CRAC Thresholds if additional sources of liquidity are acquired in FY 2006, 2007, or 2008.

The Thresholds for the CRAC will be recalculated if the Administrator determines, in his sole determination, both that BPA has received sufficient assurance after the WP-07 Record of Decision (ROD) has been issued that an additional source of liquidity has become available to BPA, and that the additional source of liquidity warrants recalculation of the Thresholds. For this purpose, an additional source of liquidity includes amounts available under the Flexible PF Rate Program in excess of the $125 million used in final rate studies; however, additional liquidity, available under the Flexible PF Rate Program will in no case serve to reduce PBL's minimum liquidity reserve level, used to calculate a Treasury miss, below $50 million.

(a) Conditions occurring after the WP-07 ROD but before the beginning of FY 2009.

If additional sources of liquidity are obtained in time to include in the calculation of the CRAC for FY 2007, FY 2008, or FY 2009, then the CRAC Thresholds will be recalculated for the remaining whole fiscal years of the rate period. The revised Thresholds will be applied to the CRAC calculations for the remaining years of the rate period.

(b) Determining the Change in the CRAC Thresholds

BPA shall account for the change in liquidity by adjusting the liquidity reserve requirement in the WP-07 Final Study version of ToolKit. The thresholds for the CRAC will be established based on the same 92.6% three-year Agency TPP criterion used to set rates in the WP-07 rate proceeding. No other update will be included in the contingent recalculation of the CRAC Threshold.

The Adjusted CRAC Thresholds will be in effect for the remaining years in the rate period.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

6. The NFB Adjustment (National Marine Fisheries Service [NMFS] Federal Columbia River Power System [FCRPS] Biological Opinion [BiOp] Adjustment)

The NFB adjustment results in an upward adjustment to the CRAC Maximum Recovery Amount (Cap) for any year in the rate period if financial impacts on fish and wildlife costs arise from a specified set of circumstances. The NFB Adjustment calculation will result in an increase in the annual CRAC maximum recovery amount defined in Table B for the next fiscal year following the year the NFB Adjustment was triggered. The NFB Adjustment is applicable to each fiscal year (FY 2007 through FY 2009).

CRAC Amounts in excess of the amounts recoverable from the Maximum CRAC Recovery Amount (Cap) as shown in Table B will be proportionally collected from LLH and HLH energy, Load Variance and Demand sales under the firm power rate schedules subject to the CRAC.

(a) Triggering the NFB Adjustment

A Trigger Event is when one of the following four kinds of events arises and results in changes to BPA's FCRPS ESA obligations compared to those in the Final Studies of the WP-07 BPA rate proceeding as modified prior to this Trigger Event:

(1) A court order in *National Wildlife Federation* vs. *National Marine Fisheries*, CV 01-640-RE, or any appeal thereof ("Litigation");

(2) An agreement (whether or not approved by the Court) that results in the resolution of issues in, or the withdrawal of parties from, the Litigation;

(3) A new NMFS FCRPS BiOp; or

(4) A BPA commitment to implement Recovery Plans under the ESA that results in the resolution of issues in, or the withdrawal of parties from, the Litigation.

(b) Formula for Calculating the NFB Adjustment

The calculation will compare the financial results of the modeled operation of the power system under the total set of fish and wildlife mitigation measures actually employed, to the financial results of the modeled operation of the power system under the same set of fish and wildlife mitigation measures except with the removal of the court-ordered changes (or court-approved, etc.).

The NFB Adjustment calculation will be determined by the following formula:

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

NFB Adjustment =

Expected Net Revenue Before Financial Impacts

Minus

Expected Net Revenue After Financial Impacts

Where the NFB Adjustment is the difference in generation function modified net revenues before and after the change in the modeled operations of the power system.

Where the Expected Net Revenue Before Financial Impacts is based on the modeled operation of the power system under the total set of fish and wildlife mitigation measures actually employed for the current fiscal year, net of estimated 4(h)(10)(C) credits.

Where the Expected Net Revenue After Financial Impacts is based on the modeled operation of the power system under the same set of fish and wildlife mitigation measures except with the removal of the court-ordered changes for the current fiscal year, net of estimated 4(h)(10)(C) credits.

The adjustment to the CRAC Cap will be determined by the following formula:

Modified CRAC Maximum Recovery Amount =

Maximum CRAC Recovery Amount

Plus

NFB Adjustment

Where the Modified Maximum CRAC Recovery Amount (Cap) is the increase in the Maximum CRAC Recovery Amount by the amount calculated by the NFB Adjustment.

Where the Maximum CRAC Recovery Amount (Cap) is the maximum annual amount planned to be recovered at the beginning of the FY 2007-2009 rate period (see Table B).

Cited in Pacific Northwest Generating v. DOE, No. 05-75088 archived on December 17, 2008

(c) NFB Adjustment Timing

Prior to the beginning of each fiscal year of the rate period, BPA will determine the financial impacts, if any, of the Fish and Wildlife program resulting from a court order, an agreement related to litigation, a new NMFS FCRPS BiOp and/or Recovery Plans under the ESA. BPA will propose around mid-September the increase to the CRAC maximum recovery amount for the next fiscal year.

(d) NFB Notification Process

BPA will notify customers within thirty days of the occurrence of an NFB adjustment trigger event, as defined above. This initial notification, posted to BPA's website, will include a description of the event. However, the financial impact of the event will not be calculated until the forecast of the end-of-year AMNR calculation is performed prior to the beginning of the next fiscal year. There can be more than one NFB adjustment trigger event in any year. There will only be one calculation of the NFB adjustment amount in any year.

No later than September 30, BPA will notify customers of the calculated final CRAC percentage. Any NFB adjustment will be included in this final notification.

E. Demand Adjuster

The Demand Adjuster is applied to a customer's demand billing factor. It is a number less than or equal to one calculated by dividing the customer's Total Retail Load on the GSP by the customer's Total Retail Load on their system peak. The minimum Demand

Adjuster is 0.6 (six tenths). The Demand Adjuster is used with the demand billing factor for the Actual Partial Service Products, and with the demand billing factor for the Block with Factoring.

F. Dividend Distribution Clause

The DDC is a rate adjustment establishing criteria for the distribution of funds to customers. The DDC enables BPA to distribute funds to eligible firm power customers and establishes the mechanism to be used to make a distribution. The amount of the distribution is calculated by a formula that compares PBL Accumulated Modified Net Revenues (AMNR) (as defined by the DDC) to three annual Thresholds.

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

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

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

The DDC also applies to the calculations of:

- the 2200 aMW of Monetary Benefits provided under the Investor-Owned Utility Residential Exchange Program Settlement benefits (IOU REP Settlement benefits); and
- the benefits provided to Direct Service Industry (DSI) customers under the FY 2005 DSI Service ROD.

The DDC does not apply to:

- sales under the PF Slice Product; or
- power sales under Pre-Subscription contracts to the extent prohibited by such contracts.
- Demand Sales

1. Calculations for the Dividend Distribution Clause

Prior to the beginning of each fiscal year of the rate period (*i.e.,* FY 2007-2009), BPA will forecast the current year's end-of-year AMNR. If the forecasted AMNR is greater than the defined DDC Threshold for that fiscal year, the DDC will trigger, and a rate reduction will go into effect beginning in October of the upcoming fiscal year.

(a) Calculating the DDC Amount

DDC Amount =

Forecasted AMNR

minus

DDC Threshold, shown in Table D below.

Table D: DDC Thresholds
[Dollars in Millions]

AMNR Calculated at End of Fiscal Year	DDC Applied to Fiscal Year	DDC Threshold*	Approx. Threshold as Measured in PBL Reserves
2006	2007	$149	$1,050
2007	2008	$247	$1,050
2008	2009	$348	$1,050

* As measured by AMNR.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Where DDC Amount is the reduction in modified net revenues that a decrease in rates, due to the DDC, is intended to generate in the next fiscal year.

Where DDC Threshold is the "trigger point" for invoking a rate decrease under the DDC. The DDC Threshold is specified for the end of FYs 2006, 2007, and 2008, in Table D.

Where AMNR is generation function net revenues, as accumulated since FY 1999, and at the end of each year for FY 2006 through FY 2008. The forecast of AMNR is used to determine if the DDC Threshold has been reached, and the required Distribution Amount to be distributed. The forecast of AMNR through the end of each fiscal year will be calculated by determining the accumulated annual Modified Net Revenue (MNR) during the rate period.

Where the MNR for any given fiscal year is defined as generation function accrued revenues less accrued expenses, (in accordance with Generally Accepted Accounting Principles), with three exceptions:

(1) The calculation of MNR will exclude the impact of adopting Financial Accounting Standard 133, Accounting for Derivative Instruments and Hedging Activities (including supplemental standards issued by FASB and interpretations regarding derivatives and hedging activities), and actual Energy Northwest (EN) debt

service. (BPA has adopted FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities as amended by FASB Statements 137, 138, and 149 and interpreted by Derivatives Implementation Group issues (together, "FAS 133")* as of October 1, 2000.)

(2) The calculation of MNR will include forecasted EN debt service identified in the WP-07 Final Studies.

(3) The forecast of MNR will be based on actual generation function revenues and expenses for the first three quarters of the year and forecasted results for the remainder of the year, and will include revenues and expenses that are associated with the production, acquisition, marketing, and conservation of electric power. The transmission function accrued revenues and expenses are excluded. The MNR includes impacts on forecasted revenues, positive or negative, from contractual true-up pursuant to the Slice Agreement.

Cited in Pacific Northwest Generating v. DOE, No. 05-75628 archived on December 17, 2008

(b) Converting the DDC Amount to a Percentage

Once the DDC Amount is determined, that amount will be converted to the DDC Percentage. The DDC Percentage applies as follows:

(1) The DDC Amount is the percentage decrease applied to customers' HLH, LLH, and Load Variance Sales under the firm power rate schedules subject to the DDC adjustment.

(2) The DDC Amount will be applied to the energy rate components of the lowest cost-based rate schedule (the PF Block Product as defined by the IOU REP Settlement) used to calculate the annual IOU REP Settlement benefits. This may change the IOU REP Settlement benefits, depending on the effects of the cap and floor. This change, if any, will be factored into the calculation of the DDC Percentage.

(3) The DDC Amount will be applied to the energy rate components of the PF Block Rate used to calculate the annual DSI service benefits up to the cap set in the DSI Service ROD. The calculation of the DDC percentage will not include any anticipated effect on the DSI service benefits.

(c) Accounting for IOU Impact on the DDC Percentage

The IOU REP Settlement benefits are constrained by a cap and floor. The DDC Amount that will be distributed by increasing the IOU REP

Settlement benefits is calculated first before calculating the portion of the DDC Amount distributed to the PF products eligible for the DDC. First, it is assumed that the DDC Amount can be distributed to both the IOU REP Settlement benefits and the DDC-adjusted PF rates. A check is then performed to see whether the caps and floors constrain the portion of the DDC Amount that can be distributed via increases in the IOU REP Settlement benefits. The PF portion of the DDC Amount is the DDC Amount less the portion of the DDC Amount that can be distributed from the IOU REP Settlement benefits. The DDC Percentage is calculated by dividing the PF DDC Amount by the most current forecast of HLH, LLH, and Load Variance revenues from products subject to the DDC. Specifically:

The DDC percentage will be the lowest (smallest negative) percentage that, when applied to HLH and LLH energy and Load Variance, generates reduced net revenues (reduced PF revenue combined with possible increases in IOU REP Settlement benefits) in the amount required by the DDC formula.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

For products subject to the DDC, the DDC Percentage will be applied to HLH and LLH base energy rates and the Load Variance Rate for the twelve months beginning in October and ending the following September. The IOU Setttlement REP benefits and the DSI service benefits calculation will be adjusted if the benefits fall below the cap or rise above the floor.

The DDC Percentage cannot be so large that it reduces the LLH energy rate below $1.00/MWh.

2. DDC Adjustment Timing

In August prior to beginning of each year of the rate period, the Administrator will determine whether the expected value of the AMNR forecast at the end of that fiscal year is above the DDC Threshold. If the AMNR is forecasted to be above the DDC Threshold, the Administrator will propose, by the end of August, to assess a dividend distribution adjustment to applicable rates for power deliveries beginning in October.

Customers will be notified, on or about September 1, of the percentage decrease applicable to the base, if any, due to the DDC. The rates used to calculate the customers' bills for the following October through September will reflect the DDC decrease.

(a) DDC Notification Process

BPA shall follow the following notification procedures:

(1) Financial Performance Status Reports

Each quarter, BPA shall post to its external website (www.bpa.gov), preliminary, unaudited, *year-to-date* aggregate financial results for generation function, including AMNR.

For the 2nd and 3rd Quarter Review, BPA shall post to its external website (www.bpa.gov), the preliminary, unaudited *end-of-year* forecast of AMNR attributable to the generation function.

(2) Notice of DDC Trigger

BPA shall complete a forecast of current fiscal end-of-year AMNR in August of each year. BPA shall notify all customers and rate case parties by the end of August, in each FYs 2006-2008 (prior to the beginning of the next fiscal year), if the expected value of AMNR is forecasted to be above the DDC Threshold for that fiscal year and, if so, the extent to which BPA intends to adjust rates due to the DDC. Notification will be posted on BPA's website, and will include the audited AMNR for the prior fiscal year, the forecast of end-of-year AMNR, the calculation of the Dividend Amount, and the forecast of the DDC Percentage. The notice shall also describe the data and assumptions relied upon by BPA. Such data, assumptions, and documentation, if non-proprietary and/or non-privileged, shall be made available for review by BPA upon request.

Cited in Pacific Northwest Generating v. DOE, No. 05-75038 archived on December 17, 2008

In early September of any year in which the AMNR is forecasted to be above the DDC Threshold, BPA staff shall conduct a public forum to explain the AMNR forecast, the calculation of the Dividend Amount and the DDC Percentage, and to demonstrate that the DDC has been implemented in accordance with these GRSPs. The forum will provide an opportunity for public comment.

No later than September 30 of any fiscal year in which the AMNR is forecasted to be above the DDC Threshold, BPA will post to the BPA website the final calculation of the adjustment (as a percentage) to each product and benefit subject to the DDC as described above.

3. One-Time Adjustment of the DDC Thresholds Due to Reduced Enrollment in the Flexible PF Rate Program

In the WP-07 Final Studies, BPA included an estimate of $125 million of participation in the Flexible PF Rate Program using the Flexible PF rate option.

The additional liquidity assumed by BPA to be available was included in the calculation of the base rates and in establishing the DDC Thresholds to achieve a minimum three-year TPP of 92.6 percent. Since this source of liquidity is uncertain, BPA will reassess the final amount after August 25, 2006, and adjust the DDC Thresholds to maintain the TPP of 92.6 percent if the final amount of enrollment in the Flexible PF Rate Program is less than that assumed in the Final Studies.

(1) **Determining the actual enrollment in the Flexible PF Rate Program**

The following conditions must be satisfied prior to August 26, 2006.

(a) The Customer and BPA have each signed a formal agreement (contract) establishing the Customer as a participant in the Flexible PF Rate Program for the duration of the FY 2007-2009 rate period.

(b) The customer has secured and provided to BPA a letter of credit, stand-by letter of credit, or other mutually agreed-to form of liquidity guarantee, with a financial institution providing BPA with the assurance of payment under the terms of the Flexible PF Rate Program.

Cited in Pacific Northwest Generating v. DOE, No. 05-75038, archived on December 17, 2008

(2) **Adjusting the DDC Thresholds for a Lower Enrollment Amount in the Flexible PF Rate Program**

If a lower amount of Flexible PF revenue is available than was assumed in the WP-07 Final Studies, then the DDC Thresholds will be adjusted upward to account for the lower amount, after this new amount is rounded down to the nearest $20 million. The DDC Thresholds will be adjusted to the predetermined levels as specified in Table E.

Table E
Adjusted DDC Thresholds for
Reduced Flexible PF Revenues
[Dollars in Millions]

Flexible PF Parti-cipation	Equiv. Amt. of Reserves	PBL Liquidity Reserves	DDC Thresholds			
			Equiv. in Reserves	Thresholds in AMNR		
				2007	2008	2009
125.0	**86.3**	**88.7**	**1,050.0**	**148.8**	**247.1**	**348.2**
120.0	82.9	92.1	1,050.0	148.8	247.1	348.3
100.0	69.1	105.9	1,050.0	148.8	247.3	348.8
80.0	55.2	119.8	1,050.0	148.8	247.7	349.3
60.0	41.4	133.6	1,050.0	148.8	248.0	349.6
40.0	27.6	147.4	1,050.0	148.8	248.7	349.8
20.0	13.8	161.2	1,050.0	148.8	249.4	350.0
0.0	0.0	175.0	1,050.0	148.8	250.7	350.0

4. Contingent Recalculation of the DDC Thresholds if additional sources of liquidity are acquired in FY 2006, 2007, or 2008.

The Thresholds for the DDC will be recalculated if the Administrator determines, in his sole determination, both that BPA has received sufficient assurance after the WP-07 Record of Decision (ROD) has been issued that an additional source of liquidity has become available to BPA, and that the additional source of liquidity warrants recalculation of the Thresholds. For this purpose, an additional source of liquidity includes amounts available under the Flexible PF Rate Program in excess of the $125 million used in final rate studies; however, additional liquidity, available under the Flexible PF Rate Program will in no case serve to reduce PBL's minimum liquidity reserve level, used to calculate a Treasury miss, below $50 million.

Cited in Pacific Northwest Generating v. DOE, No. 05-75038 archived on December 17, 2008

(a) Conditions occurring after the WP-07 ROD but before the beginning of FY 2009

If additional sources of liquidity are obtained in time to include in the calculation of the DDC for FY 2007, FY 2008, or FY 2009, then the DDC Thresholds will be recalculated for the remaining whole fiscal years of the rate period. The revised Thresholds will be applied to the DDC calculations for the remaining years of the rate period.

(b) Determining the Change in the DDC Thresholds

BPA shall account for the change in liquidity by adjusting the liquidity reserve requirement in the WP-07 Final Study version of ToolKit. The thresholds for the DDC will be established based on the same 92.6% three-year Agency TPP criterion used to set rates in the WP-07 rate proceeding. No other update will be included in the contingent recalculation of the DDC Threshold.

The Adjusted DDC Thresholds will be in effect for the remaining years in the rate period.

G. Emergency NFB Surcharge

The Emergency NFB Surcharge (Surcharge) is a charge intended to recover costs as specified herein. This Surcharge is a separate adjustment from the NFB Adjustment. If a Trigger Event that is used to implement a Surcharge is also used to trigger an NFB Adjustment, the NFB Adjustment amount will be reduced by such Surcharge Amount.

The Surcharge addresses the fact that the CRAC does not produce revenues in the same fiscal year in which Financial Effects occur. The Surcharge may be implemented in fiscal years 2007, 2008, and/or 2009 if the events required to impose the Surcharge occur in those fiscal years.

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

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

The Surcharge is also based on benefits provided by BPA, of:

- the 2200 aMW of monetary benefits provided under the Investor-Owned Utility Residential Exchange Program Settlement Agreement (IOU REP Settlement benefits); and
- the benefits provided to Direct Service Industry (DSI) customers under their BPA contracts in effect during the FY 2007-09 period.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

The Surcharge is not based on sales under the following:

- the PF Slice Product; or
- Pre-Subscription contracts to the extent prohibited by such contracts.

1. Definitions

(a) A Trigger Event is when one of the following four kinds of events arises and results in changes to BPA's FCRPS ESA obligations compared to those in the Final Studies of the WP-07 BPA rate proceeding as modified prior to this Trigger Event:

(1) A court order in *National Wildlife Federation* vs. *National Marine Fisheries*, CV 01-640-RE, or any appeal thereof ("Litigation");

(2) An agreement (whether or not approved by the Court) that results in the resolution of issues in, or the withdrawal of parties from, the Litigation;

(3) A new NMFS FCRPS BiOp; or

(4) A BPA commitment to implement Recovery Plans under the ESA that results in the resolution of issues in, or the withdrawal of parties from, the Litigation.

(b) Financial Effects of a Trigger Event are changes within the fiscal year to BPA's finances due to a Trigger Event that affects power sales revenues, fish and wildlife credits, power purchases, direct program expenses of the anadromous fish component of BPA's fish and wildlife program, Corps of

Engineers and Bureau of Reclamation Operations and Maintenance expenses, and amortization of capital costs when compared with the projection of generation function revenues and expenses to the extent available, and forecasted results for the remainder of the fiscal year as modified prior to this Trigger Event. These effects are the total effects on the Federal System including the effects borne directly by Slice Customers.

(c) The Agency Within-year TPP is the probability that the Agency (i.e., both Power and Transmission) will be able to meet all Agency financial obligations to the Treasury for the fiscal year in which a Trigger Event occurred, and which takes into account for the remainder of such fiscal year: (i) all funds reasonably expected to be available to the Agency to repay the Treasury, including but not limited to financial reserves (including deferred borrowing), funds available from Energy Northwest refinancing under the Debt Optimization Program, and expense reductions and revenue increases, and BPA's then current best estimate of 4(h)(10)(C) credits for that year; and (ii) all financial obligations reasonably expected to require payment, including but not limited to Treasury payments scheduled in the WP-07 BPA rate proceeding, repayments to Treasury required pursuant to the previous exercise of liquidity tools, prepayments to Treasury required or called for by the Debt Optimization Program, and updated forecasts of other reasonably necessary expenses and reasonably necessary uses of cash.

Cited in Pacific Northwest Generating v. DOE, No. 05-75308 archived on December 17, 2008

(d) Surcharge Amount is the amount of money to be collected under this surcharge provision. Adjusted Surcharge Amount is the Surcharge Amount reduced by the amount of reduction in benefits paid to the IOUs and DSIs after accounting for the impact on the Slice True-up.

(e) Revenue Basis is the 12-month totals of revenue from firm power sales subject to the Surcharge for the fiscal year immediately prior to the fiscal year in which the Trigger Event occurred, or for FY 2007, the analogous sales that occurred in FY 2006.

(f) Customers and holders of benefit contracts (collectively Customers) is intended to represent those that are obligated to recover the costs as specified herein.

(g) Customer Percentage is the Revenue Basis associated with each Customer divided by the total Revenue Basis. Each Customer Percentage will be rounded to four decimal places.

2. Criteria for Assessing the Surcharge

The Surcharge will be assessed if: (i) a Trigger Event occurs; and (ii) the Agency Within-year TPP for the fiscal year in which the Trigger Event has occurred is calculated to be less than 80 percent when the Financial Effects of the Trigger Event, but not the revenues from the Surcharge, are taken into account. If this Agency Within-year TPP is equal to or above 80 percent, then no Surcharge will be assessed. If the Agency Within-year TPP is below 80 percent in a fiscal year, but no Trigger Event is deemed to have occurred in the fiscal year, then no Surcharge will be assessed. There can be more than one Trigger Event in a year, and therefore there could be more than one rate Surcharge implemented in a fiscal year.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

A Trigger Event may have Financial Effects in more years than the fiscal year in which the Trigger Event occurs. In such a case, the Trigger Event will be deemed to have occurred in each fiscal year in which there are Financial Effects of the Trigger Event, and subsections G.3, G.4, G.5, and G.6 will be used for each such subsequent fiscal year during the FY2007-09 rate period to determine whether the implementation of a Surcharge is warranted in each such subsequent fiscal year. If there are, or are deemed to be, multiple Trigger Events in any fiscal year, the Financial Effects of those events will be the net effect for that fiscal year.

The earliest time a determination of whether to levy a Surcharge for a subsequent fiscal year can be made is during the CRAC/NFB/DDC calculations in August or September of the year in which the Trigger Event occurs (*i.e.*, August or September prior to the start of the first such subsequent fiscal year).

No Surcharge will be levied if the Surcharge Amount described below is calculated to be less than $10 million. If the first month in which the Surcharge bill is sent out occurs during the last quarter of the fiscal year in which the Trigger Event occurred, then the Surcharge Amount in each such month shall not exceed $25 million.

3. Formula for Calculating the Financial Effects and the Surcharge Amount

The calculation of the Financial Effects will be determined as follows making use of the best information available at the time:

Financial Effects =

Expected Value Modified Net Revenue without Trigger Event

Minus

Expected Value Modified Net Revenue with Trigger Event

Where:

(a) The Expected Value Modified Net Revenue without Trigger Event is BPA's projection of what the Modified Net Revenues would be at the end of the fiscal year assuming the Financial Effects of the Trigger Event did not take place. Such projection will be based on actual generation function revenues and expenses to the extent available and forecasted results for the remainder of the fiscal year, and will include revenues and expenses that are associated with the production, acquisition, marketing, and conservation of electric power, including BPA's best estimate of 4(h)(10)(C) credits.

(b) The Expected Value Net Revenue with Trigger Event is the identical projection as made in (1) above except that BPA will assume the Financial Effects of the Trigger Event did take place.

Cited in Pacific Northwest Generating v. DOE, No. 05-75608 archived on December 17, 2006

The calculation of the Surcharge Amount will be determined as follows making use of the best information available at the time:

The Surcharge Amount =

Financial Effects

Minus

Expense Changes Borne by Slice Customers

Where:

(a) The Expense Changes Borne by Slice Customers are the estimated costs subject to the Annual True-up Adjustment for Actual Costs, including changes in IOU and/or DSI benefits due to the Surcharge.

The portion of the Surcharge Amount allocated to the IOU and DSI customers in determining the Adjusted Surcharge Amount is set forth in subsection G.4 below. The Adjusted Surcharge Amount to be collected from firm power purchasers subject to the Surcharge, excluding the IOU and DSI customers, is set forth in subsection G.5 below.

4. Calculating IOU and DSI Portions of the Surcharge Amount

For the purpose of determining the Adjusted Surcharge Amount, a determination will be made of the portion of the Surcharge Amount to be realized from a reduction, if any, in the benefit payments to the IOUs and DSIs. Such reduction, if any, results from an increase in the rate ($/MWh) used to calculate IOU and DSI benefits and will be realized by reducing the payments to the IOUs and DSIs

during the months for which the Surcharge is billed to PF loads subject to the Surcharge.

Calculation and application of the Surcharge as applied to IOU REP Settlement benefits will be subject to the cap and floor on IOU benefit amounts under REP Settlement Agreements. Calculation and application of the Surcharge as applied to DSI benefits will be subject to the cap on DSI benefit amounts under the DSI agreements.

For the purpose of determining the Adjusted Surcharge Amount, IOU and DSI benefits will be recalculated through adjustment of the PF rate used to calculate benefits under the IOU REP Settlement Agreements and the PF rate used to calculate the DSI benefits until the sum of:

Cited in Pacific Northwest Generating v. DOE, No. 05-75688, archived on December 17, 2008

The Surcharge Amount =

the increased revenue that would be realized from a Surcharge on PF and other products subject to the Surcharge

Plus

the calculated reduction (in light of the annual effects of the cap and floor on IOU REP Settlement benefits and cap on DSI benefits) in IOU REP Settlement benefits and DSI benefits, if any, (less the effect of this reduction on the Slice True-up Adjustment Charge) that would result from such Surcharge

Any reduction in IOU or DSI benefits determined as described above will be reflected in benefit payments for the same months during which the monthly Surcharge bill is sent out.

5. Calculating the Portion of the Surcharge and the Payment Schedule for Other Customers

If the calculation in subsection G.4 above, yields a reduction in the IOU and/or DSI benefits, the total reduction during the period for the Surcharge will be calculated and subtracted from the Surcharge Amount to determine the portion of the Surcharge Amount that will be collected from customers (other than the IOUs and DSIs) that are subject to the Surcharge (Adjusted Surcharge Amount).

Each Customer Percentage will be multiplied by the Adjusted Surcharge Amount, and divided by the number of billing months payable before the end of the then current fiscal year to determine each customer's Monthly Surcharge, subject to the limit set forth in subsection G.2 above. The Monthly Surcharge will be added to each customer's bill for each billing month payable before the end of the current fiscal year. In the discretion of the Administrator, BPA may collect the

Adjusted Surcharge Amount by modifying the Monthly Surcharge to collect less in earlier months and more in later months of the fiscal year.

If the Surcharge is applied to the PF rate in FY 2007, the FY 2006 data used to perform the calculation described in the paragraph above will be the FY 2006 revenue without FB CRAC or SN CRAC revenue; revenue used in this calculation from pre-Subscription customers (except the Hungry Horse pre-Subscription customers) will be increased for these calculations by adding the LB CRAC rates for the first and second halves of FY 2006.

6. Surcharge Notification Process

BPA shall use the following procedures depending on if one or both of the criteria defined in subsection G.2 occur:

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

(a) Notification Procedures When a Trigger Event and Agency Within-year TPP Criterion Occur at Different Times During the Same Fiscal Year

(1) Notice of Trigger Event Only

If, at the time a new Trigger Event (*i.e.*, not a deemed Trigger Event) occurs, BPA has not determined pursuant to the subsection G.6.(a)(1) methodology that the Agency Within-year TPP is below 80 percent, then BPA shall notify customers within seven (7) days of the occurrence of the Trigger Event. This initial notice will be posted to BPA's website and provided by e-mail to those listed on the service list for the WP-07 BPA rate proceeding. Such notice will include a description of the Trigger Event and the time and location of a public workshop to be conducted no later than two weeks after the issuance of the notice.

At the workshop, BPA will explain the Trigger Event and the estimated Financial Effects. BPA will provide and explain the data, models, and assumptions used to calculate the Surcharge Amount and Adjusted Surcharge Amount. BPA staff will respond to reasonable requests for data and calculations and will accept comments on any of the foregoing topics. At the customers' request, Power Business Line (PBL), Account Executives shall provide customers their Customer Percentage of the Adjusted Surcharge Amount or benefit reduction, calculated pursuant to subsection G.4 or G.5 as applicable.

No Surcharge will be assessed under this subsection G.6.(a)(1) until the procedural requirements of subsection G.6.(a)(2) have been satisfied.

(2) Notice of Agency Within-year TPP Falling Below 80 Percent Following a Trigger Event

If at some time later in the fiscal year in which a Trigger Event has occurred BPA determines using the methodology developed pursuant to the subsection G.6.(a)(1) that the Agency Within-year TPP is below 80 percent, BPA will notify customers within seven (7) days of such a determination. In addition, this notice will be posted to BPA's website and provided by e-mail to those listed on the service list for the WP-07 BPA rate proceeding.

Such notice will include the time and location of a public workshop to be conducted no later than seven (7) days after the issuance of the notice. This notice will also include updated calculations of the Financial Effects and the Agency Within-year TPP. Concurrently, BPA's PBL Account Executives will inform customers of their Customer Percentage of the Adjusted Surcharge Amount or reduction to their benefits due to the Surcharge, as applicable.

Cited in Pacific Northwest Generating v. DOE, No. 05-75038 archived on December 17, 2008

At this workshop, BPA will explain the calculation of the Agency Within-year TPP, the Surcharge Amount and the Adjusted Surcharge Amount, as set forth in subsections G.2, G.3, G.4, and G.5, including the monthly shape of payments. BPA will provide data and assumptions used in these calculations. BPA staff will respond to relevant requests for data and calculations and will accept comments on any of the foregoing topics.

(b) Notification Procedures when Trigger Event and Agency Within-year TPP Criterion Occur at the Same Time

If a Trigger Event has occurred and BPA concurrently determines using the methodology developed pursuant to subsection G.6.(a)(1) that the Agency Within-year TPP is below 80 percent, then BPA shall notify customers of those two events within seven (7) days of the Trigger Event. In addition, this notice will be posted to BPA's website and provided by e-mail to those listed on the service list for the WP-07 BPA rate proceeding.

This notice will include the time and location of a public workshop to be conducted no later than seven (7) days after the issuance of the notice. Such notice will also include BPA's calculations of the Financial Effects and the Agency Within-year TPP. Concurrently, BPA's PBL Account Executives will inform customers of their Customer Percentage of the Adjusted Surcharge Amount and reduction to their benefits due to the Surcharge, as applicable.

At this workshop, BPA will explain the calculations of the Agency Within-year TPP, the Surcharge Amount and the Adjusted Surcharge Amount, as set forth in Subsections G.2, G.3, G.4, and G.5, including the monthly shape of payments. BPA will provide data and assumptions used in these calculations. BPA staff will respond to relevant requests for data and calculations and will accept comments on any of the foregoing topics.

7. Final Notification Procedures for Monthly Surcharge and Fiscal Year Surcharge Amount to Be Paid By Customers

BPA will provide written Final Notice to each Customer in accordance with the notice provisions of their BPA contract no later than seven (7) days following the conclusion of the workshop described in subsection G.6.(a)(2) or G.6.(b). Such Final Notice will state the monthly Adjusted Surcharge Amount and the total Surcharge Amount to be recovered from each customer by September 30 of the fiscal year that the Surcharge is in effect.

Cited in Pacific Northwest Generating v. DOE
No. 95-75638 archived on December 17, 2008

The monthly Adjusted Surcharge Amount will be included on a bill to power customers, and will be payable in accordance with the applicable payment provisions of the customer's power contract. The first monthly Adjusted Surcharge Amount will be billed no sooner than 30 days following the Final Notification described in this subsection G.7.

8. Process Following Implementation of Surcharge

Within thirty (30) days of the Final Notice described in subsection G.7 of implementation of a Surcharge, BPA will convene two or more meetings, the schedule for which will not exceed sixty (60) days.

At the first meeting, customers and interested persons may request additional information and explanations about the Trigger Event, its Financial Effects, and the updated Agency Within-year TPP. Customers and interested persons may also request information regarding BPA's financial performance to date, revenue and expense forecasts for the remainder of the fiscal year, the calculation of the Surcharge Amount and Adjusted Surcharge Amount, and any other materials related to the Surcharge then in effect. BPA will provide responses to relevant information requests as promptly as possible but in any case no later than 48 hours prior to the last meeting. Subsequent meetings may be held, as necessary.

At the last meeting, customers and interested persons may ask questions of and present their views to the Administrator. Customers and interested persons may also submit their views in writing to the Administrator within seven days after the meeting.

Based on the information and views presented during the process provided for in this subsection G.8 and not later than twenty (20) days after the final meeting, the Administrator will issue a close-out letter that addresses the issues raised in the meetings, the need for the Surcharge and whether the Surcharge is set at the appropriate level, all in accordance with these GRSPs. If the Administrator determines that the Surcharge Amount needs to be adjusted, the close-out letter will establish the refund or credit amount to Customers for the amounts over-collected or adjust the Surcharge then in effect for the remainder of the year or remove it entirely if one or more of the following occur:

(a) the Agency Within-year TPP, not including future surcharge payments, is determined at the time of the close-out letter, using the methodology developed pursuant to subsection G.9, to be greater than 99 percent;

(b) an updated Surcharge calculation results in a change compared to the Surcharge calculated in subsection G.7.

(c) in BPA's initial determination to assess the surcharge, BPA did not follow the Within-year TPP methodology established pursuant to subsection G.9.

Cited in Pacific Northwest Generating v. DOE, No. 05-75038 archived on December 17, 2008

9. Agency Within-year TPP Methodology Proceeding

Within 120 days following the WP-07 ROD, BPA will begin a proceeding to describe in detail the methodology to be used to calculate the Agency Within-year TPP, consistent with subsection G.2. The description of the Agency Within-year TPP methodology will include: (1) how forecasts for the remainder of such a fiscal year will be made; (2) how forecasts for the Agency's expected funds and financial obligations will be made; (3) which revenues, expenses or other funds and financial obligations will be treated deterministically and probabilistically; (4) which tools will be used for performing probabilistic calculations; and (5) how and from what sources the data for major components of the Agency Within-year TPP will be obtained or derived.

The Agency Within-year TPP methodology will not be changed during the FY 2007-09 period except through a subsequent proceeding which would trigger at least 45-days before Surcharge bills could be sent to customers that rely on the new methodology.

H. Excess Factoring Charges

1. Excess Within-Day Factoring Charge

The within-day factoring test compares the hour-by-hour shape of the customer's load to 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.

Excess Within-Day Factoring Charge, for any hour(s) in the month, applies to amount of hourly energy in excess of the authorized maximum energy amounts defined by the customer's within-day load shape.

(a) *The total amount of Excess Within-Day Factoring Charge during the HLHs of the month shall be billed the greater of:*

(1) 5 mills/kWh;

(2) Among all HLH periods of the billing month, the maximum within-day difference between the highest hourly HLH California Independent System Operator (CAISO) Supplemental Energy price (NP15) and the lowest hourly HLH CAISO Supplemental Energy price (NP15).

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

(b) *The total amount of Excess Within-Day Factoring Charge during the LLHs of the month shall be billed the greater of:*

(1) 5 mills/kWh;

(2) Among all LLH periods of the billing month, the maximum within-day difference between the highest hourly LLH CAISO Supplemental Energy price (NP15) and the lowest hourly LLH CAISO Supplemental Energy price (NP15).

In the event that the index for ISO Supplemental Energy expires, that index will be replaced for the purpose of deriving Excess Within-Day Factoring Charges by another hourly energy index at a hub at which Northwest parties can trade.

2. Excess Within-Month Factoring Charges

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-to-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, the customer resource deliveries were zero for a particular day. The within-month factoring test is equipped to address that type of instance. 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.

Excess Within-Month Factoring Charge applies to that amount of energy take that either exceeds or falls short of a range defined by: (1) a flat load placement on BPA; and (2) a load placement that follows the customer's actual load shape.

The Excess Within-Month Factoring quantities are reduced by any Unauthorized Increase Energy amounts in the like diurnal period, and only the residual is charged the Excess Within-Month Factoring Charge.

(a) *The Excess Within-Month Factoring during the HLHs of the month shall be billed the greater of:*

(1) 5 mills/kWh.

(2) The highest peak Dow Jones Mid-Columbia (DJ Mid-C) Index price for firm power during the month LESS the lowest peak DJ Mid-C Firm Index price for firm power during the month.

Cited in Pacific Northwest Generating v. DOE, No. 05-75028 archived on December 17, 2008

(3) The highest average HLH CAISO Supplemental Energy price (NP15) (average of hours 7 through 22, excluding Sundays and holidays) during the month LESS the lowest average HLH CAISO Supplemental Energy price (NP15) for the same period.

(b) *The Excess Within-Month Factoring during the LLHs of the month shall be billed the greater of:*

(1) 5 mills/kWh.

(2) The highest offpeak DJ Mid-C Index price for firm power during the month LESS the lowest offpeak DJ Mid-C Index price for firm power;

(3) The highest average LLH CAISO Supplemental Energy price (NP15) (average of hours 1 through 6, and 23, and 24 Monday through Saturday; average of hours 1 through 24 Sundays and holidays) during the month LESS the lowest average LLH CAISO Supplemental Energy price (NP15) for the same month in the same time period.

The DJ Mid-C Index definitions for HLHs (or Peak) and LLHs (or offpeak) will be adjusted, as necessary, to be consistent with (comport with) BPA's definition for HLH and LLH periods.

In the event that the index for CAISO Supplemental Energy or DJ Mid-C Index expires, that index will be replaced for the purpose of deriving Excess Within-Month Factoring Charges by another hourly or diurnal energy index at a hub at which Northwest parties can trade.

I. Flexible New Resource Firm Power (NR) Rate Option

The Flexible NR rate option will be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option. The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The customers purchasing under the Flexible NR rate option purchase the same set of power products and services that they would otherwise purchase under the rate schedule. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying the following condition:

Equivalent NPV Revenues: Forecasted revenues from a Purchaser under the Flexible 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 NR rate schedule Section II been applied to the same sales.

Cited in Pacific Northwest Generating v. DOE, No. 05-75038 archived on December 17, 2008

The Flexible NR rate contract may establish a limit on the amount of power purchased at the Flexible NR rate. In this case, purchases beyond the contractual limit will be billed at the Demand and Energy (and Load Variance, if appropriate) charges specified in the NR rate schedule Section II, unless such power would be charged as an Unauthorized Increase.

J. Flexible Priority Firm Power (PF) Rate Option

The Flexible PF rate option will be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option. The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The customers purchasing under the Flexible PF rate option purchase the same set of power products and services that they would otherwise purchase under the rate schedule. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying the following condition:

Equivalent NPV Revenues: Forecasted revenues from a Purchaser under the Flexible PF 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 PF rate schedule Section II been applied to the same sales.

The Flexible PF rate contract may establish a limit on the amount of power purchased at the Flexible PF rate. In this case, purchases beyond the contractual limit will be billed at the Demand and Energy, (and Load Variance if appropriate) charges specified in the PF rate schedule Section II, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the PF rate and associated GRSPs, any rights and obligations of BPA and a customer arising out of the customer's election to participate in the Flexible PF Rate Program by purchasing under the Flexible PF Rate Option will survive and be fully enforceable until such time as they are fully satisfied.

K. Green Energy Premium

1. Overview of the Premium

The Green Energy Premium (GEP) is a premium ranging from $0-40/MWh that a customer elects to pay and which is applied to the amount of Environmentally Preferred Power (EPP) MWh that the customer has elected to purchase. Forecasted GEP revenue is the estimated avoided cost of renewable energy credit sales based on credits produced by BPA's renewable resource portfolio. BPA guarantees the customer paying the premium that BPA will produce an amount of renewable energy credits equal to the amount of energy subject to this adjustment. The GEP will be charged in a line item on the monthly power bill of each participating customer. The negotiated GEP will be based on cost and the market value of the non-power renewable attributes as well as applicable costs associated with the purchase. Such costs may include, but are not limited to:

Cited in Pacific Northwest Generating v. DOE
No. 05-75038 archived on December 17, 2008

- Avoided Costs of renewable energy credits based on existing BPA resources
- Avoided Costs of renewable energy credits based on new or proposed BPA resources
- Endorsement fees for specific EPP resources.
- Actual costs of Market purchases of renewable energy credits.

2. Calculation and Application of the Premium

(a) Determination of the Premium

For a customer buying power from BPA under a requirements firm power sales contract, the amount of EPP and the GEP will be determined as part of the product selection process and will be completed as part of the power sales contract negotiation. The charge will not exceed $40 per MWh and may be as low as zero. The premium will be zero if the avoided cost of the GEP resource(s) dedicated to the customer is zero. The GEP will recover the average forecast avoided cost of the renewable resource credit portfolio inventory available for this product.

(b) Determination of Individual Customer GEP

(1) Customers will be provided notice of the availability of specific GEP products and associated premiums. The total GEP for the customer will be based on the customer's elections of product amounts and content.

(2) The average annual energy charge will be calculated as the average per kWh charge for an annual flat undelivered product using the energy charges applicable to the customer. Where customers are purchasing under more than one rate schedule, the average energy charge will be calculated using expected loads and applicable rate schedules.

(3) The individual customer GEP for billing will be the total cost of the product selected by the customer minus the average annual energy charge.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

(c) Application of the GEP

The GEP will be applied after BPA has determined all other charges and credits except the Conservation Rate Credit (CRC) line item, on the participating customer's power bill.

(d) Billing for the Premium

The customer's bill will include a line item showing the kWh amount of EPP purchased times the GEP for the products elected and the total cost. The calculation will appear as:

(EPP amount) kWh * GEP mills/kWh = $X

L. Low Density Discount (LDD)

1. Application and Definitions

For eligible Purchasers as defined in section 2 below, a discount shall be applied each billing month to BPA's charges for the following components of the PF Preference Rate, the PF Exchange Rate, and the New Resource Rate: (1) Demand; (2) HLH purchases; (3) LLH purchases; and (4) Load Variance. The Low Density Discount (LDD) shall not be applied to Unauthorized Increase Charges, Excess Factoring Charges, transmission charges or any other charges. The discount shall be revised annually based on data supplied by June 30 of each Calendar Year (CY) for the previous CY and shall become effective on the upcoming October 1.

(a) The Kilowatt-hour/Investment Ratio

The kWh/Investment (K/I) ratio is calculated annually based on the data supplied by June 30 for the previous CY. The K/I ratio is calculated by dividing the Purchaser's Total Retail Load during the CY by the value of the Purchaser's depreciated electric plant (excluding generation plant) at the end of the CY.

(b) The Consumers/Mile of Line Ratio

The Consumers/Mile of Line (C/M) ratio is determined annually using the data supplied by June 30 for the previous CY. The C/M ratio is calculated by dividing the maximum number of consumers within the distribution system, in any one month during the CY, by the end of CY number of pole miles of distribution.

Cited in Pacific Northwest Generating v. DOE, No. 05-75038 archived on December 17, 2008

Consumer means every billed consumer regardless of usage. Separately billed services for water heating and security lights are not counted as an additional billed consumer.

The number of pole miles of distribution line means the end of CY pole miles. Distribution lines are defined as lines that deliver electric energy from a substation or metering point, at a voltage of 34.5 kilovolt (kV) or less, to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities. (Service drops are considered service facilities.)

These calculations shall be based on CY data provided from the Purchaser's annual financial and operating reports. The Purchaser shall certify that the data submitted is correct and that no loads gained as provided in section 6, Retail Access Exclusion, are receiving LDD benefits.

In calculating these ratios, BPA shall compile the data submitted by the Purchaser based on the Purchasers entire electric utility system in the PNW. For Purchasers with service territories that include any areas outside the PNW, BPA shall compile data submitted by the Purchaser separately on the Purchaser's system in the PNW and on the Purchaser's entire electric utility inside and outside the PNW. BPA will apply 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 will be determined by the lesser amount of discount applicable to its PNW system or to its combined system inside and outside the PNW. BPA, in its sole discretion, may waive the requirement to submit separate data for the Purchaser with a small amount of its system outside the PNW. Results of the calculations shall not be rounded.

A Purchaser who has not provided BPA with the requisite pieces of data needed to calculate the K/I and C/M ratios by June 30 of each year, for the prior CY, shall be declared ineligible for the LDD, effective the upcoming October 1.

If a Purchaser's data was submitted on time and a revision is necessary to the data, the revised data must be resubmitted no later than 12 months after the original submission date to be considered for an adjustment.

2. Eligibility Criteria

To qualify for a discount, the Purchaser must meet all five of the following eligibility criteria:

(a) the Purchaser must serve as an electric utility offering power for resale;

(b) the Purchaser must agree to pass the benefits of the discount through to the Purchaser's eligible consumers within the region served by BPA;

(c) 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;

(d) the Purchaser's K/I ratio must be less than 100; and

(e) the Purchaser's C/M ratio must be less than 12.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

3. Discounts

The Purchaser shall be awarded the following discount beginning October 1, 2006, in accordance with section 4 below. The discount will be the sum of the two potential discounts for which the Purchaser qualifies, based on the following Table F. The discount shall not exceed 7 percent.

Table F
LDD Percentage Discount Table

Percentage Discount	*Applicable Range for kWh/Investment (K/I) Ratio*	*Applicable Range for Consumers/Mile (C/M) Ratio*
0.0%	35.0 ≤ X	12.0 ≤ X
0.5%	31.5 ≤ X < 35.0	10.8 ≤ X < 12.0
1.0%	28.0 ≤ X < 31.5	9.6 ≤ X < 10.8
1.5%	24.5 ≤ X < 28.0	8.4 ≤ X < 9.6
2.0%	21.0 ≤ X < 24.5	7.2 ≤ X < 8.4
2.5%	17.5 ≤ X < 21.0	6.0 ≤ X < 7.2
3.0%	14.0 ≤ X < 17.5	4.8 ≤ X < 6.0
3.5%	10.5 ≤ X < 14.0	3.6 ≤ X < 4.8
4.0%	7.0 ≤ X < 10.5	2.4 ≤ X < 3.6
4.5%	3.5 ≤ X < 7.0	1.2 ≤ X < 2.4
5.0%	X < 3.5	X < 1.2

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

4. LDD Phase-Out Adjustment

If the Purchaser satisfies the eligibility criteria (2. a. through e.), and the calculated discount differs from the existing discount by more than one-half of 1 percent, the applicable discount will be:

(a) the existing discount plus one-half percent if the calculated discount exceeds the existing discount; or

(b) the existing discount minus one-half percent if the calculated discount is less than the existing discount.

The foregoing formula will be applied each October 1 until the then-current calculated discount is fully phased out.

The Purchaser is not eligible to receive any discount, effective each October, if the Purchaser fails to meet the eligibility criteria in section 2. a. through e.

For Purchasers with Pre-Subscription power sales contracts who are converting to Subscription power sales contracts on October 1, 2006, the "existing discount" shall be calculated by BPA using BPA's 2002 GRSPs and calendar year 2004 data. This "existing discount" will only be used for determining the Purchaser's Phase-In Phase-Out Adjustment for the first year of the rate period. The Purchaser shall provide BPA with such calendar year 2004 data by October 1, 2006.

5. Additional Adjustment for Very Low Densities

If a Purchaser's C/M ratio is 3 or less and its K/I ratio is 26 or less, after determination of the discount pursuant to sections 3 and 4 above, an additional one-half percent shall be added to the Purchaser's discount, but the total discount shall not exceed 7 percent. In subsequent years, the one-half percent added to the discount pursuant to this section shall not be included when determining the applicable discount in section 4 above.

6. Retail Access Exclusion

Load that is gained by a Purchaser as a direct result of retail access rights established by Federal, state, or local legislation, and that would not otherwise have been gained absent such legislation, is not eligible to receive the benefits provided by the LDD. The Purchaser shall not pass the benefits of the LDD to its gained load consumers.

Cited in Pacific Northwest Generating v. DOE; No. 05-75638 archived on December 17, 2008

7. Application of the LDD to Slice Product

To be eligible for the LDD, customers that purchase the Slice product must meet the eligibility criteria under section 2.

The LDD benefit for Slice customers will be determined and applied as follows:

By September of each year, BPA will establish a dollars/MWh discount rate for each one-half percent discount bracket, from 0.5 percent to 7 percent. The dollars/MWh discount rate for each bracket will be determined by using billing data of customers within the same non-Slice LDD percentage bracket. Those customers' total dollars in non-Slice LDD discounts they received will be divided by the total eligible MWh purchased. This will result in a dollars/MWh rate that can then be used as the yearly/monthly discount for a Slice customer that is eligible, under section 3, to receive the same discount. BPA will use billing data from the previous CY from the non-Slice LDD recipients when calculating the dollars/MWh discount rate for Slice product recipients. When there are no non-Slice LDD recipients available in a given discount bracket to calculate the $/MWh value, it is appropriate to determine a linear relationship using a regression analysis to arrive at a $/MWh value for that bracket. When there is an increase or decrease in the PF rate for HLH and LLH billing determinants, not due to the Targeted Adjustment Charge (TAC), CRAC, NFB Adjustment, Emergency NFB Surcharge, or the DDC, the regional average increase or decrease will be applied to the $/MWh rate that coincides with the increase or decrease rate(s) for the non-Slice LDD recipients for the same period.

The rate will only be applied to that portion of Slice power being purchased that is requirements power. This quantity is defined in the Slice Contract as Critical Slice Amount. The annual Slice true up will include an LDD true-up if based on estimates. If it is based on after-the-fact monthly data, no true-up is necessary.

M. Rate Melding

BPA's rate proposal allows the customers more than one rate choice. Separately tracking and administering the customers rate choices and maintaining the distinction would increase BPA's overall cost of providing rate choices. For administrative simplicity upon mutual agreement between BPA and the customer, BPA may offer to meld the customer's rate choices into a single composite set of rates that reflects the specific choices made by the customer. BPA will ensure that this melded set of rates will result in a bill that is nearly mathematically equivalent to applying the customer's individual choices throughout the rate period. BPA will provide the affected customer the calculations it used to establish the melded rates and provide 30 days for the customer to review and accept the melding calculation before it implements the melded rates. Melded rates established by BPA will continue until one of the customer's rate choices expires, or a rate adjustment occurs that is provided for under the chosen rate schedules (*e.g.,* CRAC), or a significant change in the loads applicable to the rates occurs.

Cited in Pacific Northwest Generating v. DOE, No. 03-75638 archived on December 17, 2008

N. Slice True-Up Adjustment

1. Calculation of the Annual True-Up

Following the end of each Fiscal Year, BPA will calculate the difference between the Actual Slice Revenue Requirement and the Slice Revenue Requirement for that 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 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 Generally Accepted Accounting Principles (GAAP). For example, after the end of FY 2007, BPA will calculate the difference between the Actual Slice Revenue Requirement for the Fiscal Year (FY) ending September 30, 2007 (FY 2007) and the Slice Revenue Requirement for FY 2007 (*see* Table 1, Slice Product Costing and True-Up Table).

Table 1
Slice Product Costing and True-Up Table

($000s)

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

Cited in Pacific Northwest Generating v. DOE, No. 08-75638 archived on December 17, 2008

Table 1, continued
Slice Product Costing and True-Up Table

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

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 15, 2008

The difference between the Actual Slice Revenue Requirement and the Slice Revenue Requirement will be the basis for the Slice True-Up Adjustment Charge (or Credit). This difference, if the Actual Slice Revenue Requirement for the individual FY exceeds the Slice Revenue Requirement for that same individual FY, can be positive, which results in a True-Up Adjustment Charge. Alternatively, this difference can be negative, if the Actual Slice Revenue Requirement for the individual FY is less than the Slice Revenue Requirement for that same individual FY, which results in a True-Up Adjustment Credit.

To calculate each Slice customer's share of this difference between the Actual Slice Revenue Requirement and the Slice Revenue Requirement for the applicable FY, BPA will multiply this difference by the Slice customer's Selected Slice Percentage. For example, if the Slice customer's Selected Slice Percentage is 5 percent, then the difference will be multiplied by 0.05 to calculate the Slice customer's share of the difference. These amounts will be included on Slice customers' bills as the Slice True-Up Adjustment Charge or Credit.

Cited in Pacific Northwest Generating v. DOE
No. 05-75828 archived on December 17, 2008

2. Slice Implementation Expenses

In addition, following the end of each FY, BPA will calculate the amount of Slice Implementation Expenses incurred during that FY. Slice customers will be charged for 100 percent of these expenses, and these expenses will be allocated on the basis of each customer's Selected Slice Percentage, relative to the total of all the customers' Selected Slice Percentage. For example, if the Slice customer's Selected Slice Percentage is 5 percent, this percentage is divided by the total percentage of Slice sold (currently 22.6278 percent) to obtain that customer's share of the Slice Implementation Expenses (*e.g.*, 5 percent divided by 22.6278 percent equals 35.35 percent). These amounts will be included on Slice customers' bills as a Slice True-Up Implementation Expense charge at the same time as the Slice True-Up Adjustment Charge or Credit.

3. Individual Charges and Individual Credits

For some customers who purchase additional services from BPA or who elect certain contractual options, BPA will calculate the amount of Individual Charges that will be added to their bills at the same time as the Slice True-Up Adjustment Charge. For some customers who elect certain contractual options, BPA will calculate the amount of Individual Credits that will be factored into their bills at the same time as the Slice True-Up Adjustment Charge or Credit.

O. Supplemental Contingency Reserves Adjustment (SCRA)

The energy charges stated in the IP-07 rate schedule may be adjusted to reflect the negotiated Supplemental Contingency Reserves Adjustment (SCRA) adjustment. PBL will negotiate with any DSI interested in providing Supplemental Contingency Reserves (Supplemental Reserves). Supplemental Reserves refers to generating capacity, and

associated energy, fully available within 10 minutes notice of a system disturbance. This is a flexible rate that will allow BPA to negotiate company-specific interruption rights and will establish a value tied to the company-specific arrangement based on the amount and quality of reserves provided. The maximum amount PBL may pay for Supplemental Reserves from a DSI is capped at $5.63/kW-mo. This maximum value is based on the FERC-approved embedded cost methodology.

The suitability and quality of the Supplemental Reserves will be measured by whether they have certain characteristics, some of which are required and others optional. Any Supplemental Reserves purchased by PBL must be consistent with North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) standards and criteria:

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

1. The interruptible load must be offline within five minutes after a call by BPA;

2. In the event of a system disturbance, the interruptible load must be accessible prior to a request for reserves from other NWPP parties; and

3. The interruptible load must be available to be offline for up to 60 minutes.

In addition to these required characteristics, the issues identified below will help define when PBL may pay the maximum value for Supplemental Reserves:

1. The extent to which PBL has the discretion when and how to use all operating reserves and to determine what resources to call on in the event of a system disturbance; and

2. Whether there are limitations on the number of times or total minutes the reserves may be utilized.

Pursuant to established criteria met and performance demonstrated, BPA will satisfy its obligation to provide a reserves credit or payment to the DSI through TBL's Transmission Contracts and the Stability Reserves Credit or through other contracts as negotiated.

P. Targeted Adjustment Charge (TAC)

1. Availability

The TAC pertains to the PF rate schedule, except for the Slice Product and the PF Exchange Power Product. The TAC also applies to purchases under the NR Rate. The TAC applies to firm power requirements service to regional firm load that results in an unanticipated increase in BPA's projected loads within the rate period. The TAC will be applied to the applicable rate for requirements service requested after June 30, 2005. TAC also applies to customers that add load

through retail access including load that was once served and returns under retail access.

TAC will also 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 5(b)(1)(A) or 5(b)(1)(B) resources. The TAC will not apply to purchases included in a customer's initial Subscription contract.

If a public agency customer that requests requirements service from BPA is annexing or otherwise taking on the obligation of load from another public agency customer and the request to annex or take on load obligation and the reduction in obligation are equal amounts such that BPA's total load obligation does not increase, BPA may exempt the newly acquired load from the TAC and apply the PF-07 rate. The TAC will apply if the annexed requirements service has been previously served by that customer's 5(b)(1)(A) or 5(b)(1)(B) resources.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

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 a Subscription Settlement Agreement as amended, the IOU will return a pro rata amount of its Subscription Settlement benefits calculated in annual aMW by assignment to BPA. BPA will provide such benefits to the public agency customer by exempting from the TAC charge that amount of 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 benefit assigned by the IOU to BPA. This, in effect, will reduce the overall TAC charge. 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 the end of the rate period whichever occurs first. The TAC will not apply to unanticipated loads less than 1 aMW per year if it is determined to be inconsequential to overall costs. For any TAC load greater than 1 aMW per year, the entire amount will be subject to the TAC, not just the amount above 1 aMW. If a new public requests service, the TAC, if any, will apply until September 30, 2009.

If a customer is serving a portion of its load with a certifiable renewable resource eligible for the Conservation Rate Credit (CRC), or 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, during the FY 2007-09 rate period, requirements firm power service for such load at the end of the specified contract period at PF Preference (PF-07) rate without being subject to the TAC. This limited exception applies to the first 200 aMW in any contract year, or to amounts that BPA specifies in accordance with its Policy on the Determination of Net Requirements.

2. Energy Charge

The TAC is a monthly mills/kWh adjustment to the HLH and LLH energy rates specified in the WP-07 rate schedule, and is applied to that portion of the Purchaser's load that is subject to the TAC. The TAC rate adjustment will be established based on the following formula:

TAC = [(Incr $ * Incr Amt) – (Rate $ * Incr Amt)]/TAC Amt

where:

TAC Amt	=	The amount of load subject to the TAC, determined monthly.
Rate $	=	The monthly PF (or NR) energy rate shown in the applicable rate schedule.
Inventory Amt	=	Amount of energy in inventory available to serve this load based on monthly Federal system firm resource capability, estimated using critical water excluding balancing purchases and purchases for system augmentation, from the WP-07 rate case with updates if BPA determines that is necessary.
Incr $	=	Monthly cost to BPA, including a handling fee, of incremental power purchases expressed in mills/kWh. These costs also may include, where applicable, wheeling, ancillary, and other charges BPA may incur in purchasing power from other entities.
Incr Amt	=	Amount of incremental power required, determined monthly and defined as the TAC Amt minus the Inventory Amt. (If there is no available Inventory Amt, the Incr Amt will equal the TAC Amt).
TAC	=	Monthly rate adjustment in mills/kWh.

If Incr $ is less than Rate $, the TAC is 0 mills/kWh.

BPA will calculate the cost (Incr $) per month in mills/kWh of the additional power per month (Incr Amt) for a specific customer request. BPA will establish the cost of the additional power by the following method:

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

- BPA will establish the price based on BPA's monthly cost to purchase the incremental load by purchases of resources at market.

Q. Unauthorized Increase Charge (UAI Charge)

1. Charge for Unauthorized Increase in Demand

The amount of Measured Demand during a billing hour that exceeds the amount of demand the purchaser is contractually entitled to take during that hour shall be billed at the greater of:

(a) Three (3) times the applicable monthly demand charge;

(b) The sum of hourly California Independent System Operator (CAISO) Spinning Reserve Capacity prices for all HLHs in the month, at path NW1 (COB); or

(c) The sum of hourly CAISO Spinning Reserve Capacity prices for all HLHs in the month, at path NW3 Nevada-Oregon Border (NOB).

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

In the event that the hourly CAISO Spinning Reserve Capacity market expires, the Unauthorized Increase Charge for demand shall be the greater of:

(a) Three (3) times the applicable monthly demand charge;

(b) the sum of hourly or diurnal prices for all HLHs in the month, at a hub at which Northwest parties can trade, established between October 1, 2006, and September 30, 2009.

2. Charge for Unauthorized Increase in Energy

The amount of Measured Energy during a diurnal period of a billing month, day, or hour that exceeds the amount of energy the purchaser is contractually entitled to take during that period shall be billed the greater of:

(a) 100 mills/kWh; or

(b) for the month in question, the greater of:

(1) the highest diurnal Dow Jones Mid-C (DJ Mid-C) Index price for firm power; or

(2) the highest hourly CAISO Supplemental Energy price (NP15).

The DJ Mid-C Index definitions for HLHs (or peak) and LLHs (or offpeak) will be adjusted, as necessary, to be consistent with BPA's definitions for HLH and LLH periods.

In the event that either the CAISO Supplemental Energy price index or the DJ Mid-C Index expires, the index will be replaced for purposes of the Unauthorized Increase Charge for energy by:

(1) the highest price experienced for the month at the NW1 (COB);

(2) the highest price experienced for the month at the NW3 (NOB); or

(3) the highest price experienced for the month from any applicable new hourly or diurnal energy index at a hub at which Northwest parties can trade, established between October 1, 2006, and September 30, 2009.

Cited in Pacific Northwest Generating v. DOE, No. 05-75698 archived on December 17, 2008

R. West-wide Price Cap of FPS Sales

BPA will voluntarily agree to limit the price of any sales under the FPS rate schedule to the applicable west-wide price cap, if any, established by the Federal Energy Regulatory Commission.

SECTION III. DEFINITIONS

A. Power Products and Services Offered By the Power Business Line of BPA

1. Actual Partial Service Product – Simple/Complex

The Actual Partial Service Products are Core Subscription products that are available to purchasers who have a right to purchase from BPA for their requirements. These products are intended for customers who have contractual or generating resources with firm capabilities and therefore require a product other than Full Service. The Simple and Complex versions of this product category differ in that the Complex version is subject to the Factoring Benchmark tests in the billing process and to potential Excess Factoring Charges. The Simple version encompasses several possible approaches to customer resource declaration, all of which obviate the need for the Factoring Benchmark tests.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

2. Block Product

The Block Product is a Core Subscription product that is available to purchasers who have a right to purchase from BPA for their requirements. This product is available in HLH and LLH quantities per month, with the hourly amount flat for all hours in such periods.

3. Block Product with Factoring

The Block Product with Factoring is a combination of the Block Product with the Core Subscription staple-on product for Factoring Service. Factoring provides the service of distributing Block energy to follow Purchaser hourly load needs to the extent of such Block energy.

4. Block Product with Shaping Capacity

The Block Product with Shaping Capacity is a combination of the Block HLH energy product and the Core Subscription staple-on product for Shaping capacity. Shaping capacity allows the customer to preschedule Block energy with some limited shape among HLHs within a contractually specified bandwidth.

5. Capacity Without Energy

Capacity Without Energy is the stand ready obligation whereby BPA will deliver a contract specific amount of power upon contract specific notice provisions. The notice provision may be automated, such as AGC automatic deliveries, phone call schedules or any other standard utility notice provisions. The notice provision and duration of delivery is contract specific and will affect the value of the Capacity contract. No energy is sold with Capacity Without Energy; any energy delivered when the Capacity contract is exercised will be returned or paid for

under contract terms. The terms of the contract will define all parameters of the required notice provisions and all parameters of the return or payment of any energy delivered when Capacity rights are exercised.

6. Construction, Test and Start-Up, and Station Service

Power for the purpose of Construction, Test and Start-Up, and Station Service for a generating resource or transmission facility shall be made available to eligible purchasers under the Priority Firm Power (PF-07), New Resources Firm Power (NR-07), and Firm Power Products and Services (FPS-07), rate schedules. Such power is not available for the PF Exchange rate.

Construction, Test and Start-Up, and Station Service power must be used in the manner specified below:

Cited in Pacific Northwest Generating v. DOE, No. 05-75028 archived on December 17, 2008

(a) Power sold for construction is to be used in the construction of the project.

(b) Power sold for test and start-up may be used prior to commercial operation, both to bring the project online and to ensure that the project is working properly.

(c) Power sold for station service may be purchased at any time following commercial operation of the project. Once the project has been energized for commercial operation, the Purchaser may use station service power for start-up, shutdown, normal operations, and operations during a shutdown period.

(d) Power sold for Construction, Test and Start-Up, and Station Service is not available for replacement of lost generation for forced or planned outages or resource underperformance.

7. Core Subscription Products

BPA's Core Subscription Products are described in the BPA Product Catalog. Core Subscription Products are available at the posted rates for customers who have a right to purchase them.

The core products are:

- Actual Partial Service Product – Simple/Complex
- Block Product
- Block Product with Factoring
- Block Product with Shaping Capacity
- Full Service Product

8. Customer System Peak (CSP)

CSP is the largest measured HLH Total Retail Load amount in kilowatts for the billing period.

9. Full Service Product

Full Service is a Core Subscription product that is available to purchasers who have a right to purchase from BPA for their requirements. This product is available to customers who either have no resources or whose resources meet the criteria for small, non-dispatchable resources.

10. Industrial Firm Power (IP)

Cited in Pacific Northwest Generating v. DOE, No. 05-75088 archived on December 17, 2008

Industrial Firm Power (IP) is electric power that BPA will make continuously available to a DSI Purchaser subject to the terms of the Purchaser's power sales contract with BPA. Deliveries may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA. Adjustments as provided in the Purchaser's power sales contract shall be made for power restricted to provide reserves.

11. Load Variance

For Core Subscription products, Load Variance is defined as the variability in monthly energy consumption within the BPA customer's system. Through the Load Variance charge under the Full and Actual Partial Service Products, the customer's billing factors will follow actual consumption. Load Variance is not applicable to Block Product purchases. For purposes of pricing and rate tests under Pre-Subscription contracts, the Load Variance charge is deemed to correspond to the PF-96 Load Shaping charge.

12. New Resource Firm Power (NR)

New Resource Firm Power (NR) is electric power (capacity and energy) that BPA will make continuously available:

(a) for any NLSL; and

(b) for Firm Power purchased by IOUs pursuant to power sales contracts with BPA.

NR is to be used to meet the Purchaser's firm power load within the PNW. Deliveries of NR may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA.

NR is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and *force majeure* events. NR is power where BPA's TBL may agree to provide operating reserves in accordance with the standards established by the NERC, WECC, and the NWPP.

13. Priority Firm Power (PF)

Priority Firm Power (PF) is electric power (capacity and energy) that BPA will make continuously available for direct consumption or resale by public bodies, cooperatives, and Federal agencies. Utilities participating in the Residential Exchange under Section 5(c) of the Northwest Power Act may purchase PF pursuant to their Residential Exchange contracts with BPA. PF is not available to serve NLSLs. Deliveries of PF may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA.

Cited in Pacific Northwest Generating v. DOE No. 05-75038 archived on December 17, 2008

PF is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and *force majeure* events. PF is power where BPA's TBL may agree to provide operating reserves in accordance with the standards established by the NERC, WECC, and NWPP.

14. Regulation and Frequency Response

Regulation and frequency response is the generating capacity of a power system that is immediately responsive to Automatic Generation Control (AGC) signals without human intervention. Regulation and frequency response is required to provide AGC response to load and generation fluctuations in an effective manner and to maintain desired compliance with NERC AGC Control Performance.

15. Residential Exchange Program Power

Residential Exchange Program Power is power BPA sells to a Purchaser pursuant to the Residential Exchange Program. Under Section 5(c) of the Northwest Power Act, BPA "purchases" power from PNW utilities at a utility's Average System Cost (ASC). BPA then offers, in exchange, to "sell" an equivalent amount of electric power to that customer at BPA's PF rate applicable to exchanging utilities. The amount of power purchased and sold is equal to the utility's eligible residential and small farm load. Benefits must be passed directly to the utility's residential and small farm customers.

16. Slice Product

The Slice product is a power sale based upon an eligible customer's annual net firm requirements load and is shaped to BPA's generation from the FCRPS over the year. The Slice product is not a sale or lease of any part of the ownership of,

or operational rights to the FCRPS. Slice purchasers are entitled to a fixed percentage of the energy generated by the FCRPS. The Slice purchaser's percentage entitlements are set by contract. The Slice product includes both service to net requirements firm load as well as an advance sale of surplus power.

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

B. Definition of Rate Schedule Terms

1. Annual Billing Cycle

The Annual Billing Cycle is the 12 months beginning with the customer's first monthly power bill for deliveries in the first billing month starting on or after October 1.

2. Billing Demand

The Purchaser's Billing Demand is the amount of capacity to which the demand charge specified in the rate schedule is applied. When the rate schedule includes charges for several products, there may be a Billing Demand quantity for each product. The calculation of Billing Demand is described in the customer's contract.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

3. Billing Energy

The Purchaser's Billing Energy is the amount of energy to which the energy charge specified in the rate schedule is applied. When the rate schedule includes charges for several products, there may be a Billing Energy quantity for each product. Billing Energy is divided into HLH and LLH for this rate period.

4. California Independent System Operator (CAISO)

The FERC regulated control area operator of the CAISO transmission grid. Its responsibilities include providing non-discriminatory access to the transmission grid, managing congestion, maintaining the reliability and security of the grid, and providing billing and settlement services. The CAISO has no affiliation with any market participant.

5. California Independent System Operator (CAISO) Spinning Reserve Capacity

The portion of unloaded synchronized generating capacity, controlled by the CAISO, which is capable of being loaded in 10 minutes, and which is capable of running for at least two hours.

6. California Independent System Operator (CAISO) Supplemental Energy

Energy from generating units and other resources which have uncommitted capacity following finalization of the hour-ahead schedules and for which scheduling coordinators have submitted bids to the CAISO at least 30 minutes before the commencement of the settlement period.

7. Contract Demand

The Contract Demand is the maximum number of kilowatts that the Purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Purchaser.

8. Contract Energy

Contract Energy is the maximum number of kilowatt-hours that the Purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Purchaser.

9. Control Area

A Control Area is the electrical (not necessarily geographical) area within which a controlling utility operating under all NERC standards has the responsibility to adjust its generation on an instantaneous basis to match internal load and powerflow across interchange boundaries to other Control Areas.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

10. Delivering Party

The entity supplying the capacity and/or energy to be transmitted at Point(s) of Interconnection.

11. Demand Entitlement

For purchases made under contracts for Core Subscription products, Demand Entitlement is the largest HLH amount of power in kilowatts that the purchaser is entitled to receive from BPA during the billing period as specified in the contract.

12. Discount Period

The end of the rate period or the customer's contract term, whichever comes first.

13. Dow Jones Mid-C (DJ Mid-C) Indexes

Average HLH (or peak) and average LLH (or off-peak) price indices for sales of electricity at delivery points along the Mid-Columbia River, as published by Dow Jones & Company, Inc.

14. Electric Power

Electric Power is electric peaking capacity (kW) and/or electric energy (kWh).

15. Energy Entitlement

For purchases made under contracts for Core Subscription products, HLH and LLH Energy Entitlement is the sum in kWh of amounts for HLH and LLH energy respectively, that the purchaser is entitled to receive from BPA as specified in the contract.

16. Federal System

The Federal System is the generating facilities of the FCRPS, including the Federal generating facilities for which BPA is designated as marketing agent; the Federal facilities under the jurisdiction of BPA; and any other facilities:

(a) from which BPA receives all or a portion of the generating capability (other than station service) for use in meeting BPA's loads to the extent BPA has the right to receive such capability. "BPA's loads" do not include any of the loads of any BPA customer that are served by a non-Federal generating resource purchased or owned directly by such customer which may be scheduled by BPA;

(b) which BPA may use under contract or license; or

(c) to the extent of the rights acquired by BPA pursuant to the 1961 U.S.-Canada Treaty relating to the cooperative development of water resources of the Columbia River Basin.

Cited in Pacific Northwest Generating v. DOE
No. 05-75038 archived on December 17, 2008

17. Firm Power (PF-07, IP-07, NR-07)

Firm Power is electric power (capacity and energy) that BPA will make continuously available under contracts executed pursuant to Section 5 of the Northwest Power Act.

18. Full Service Customer

A Full Service customer is one who is purchasing power from BPA through the Full Service Product.

19. Generation System Peak (GSP)

The GSP is the hour of the largest HLH output of the Federal System that occurs during the customer's billing period.

20. Heavy Load Hours (HLH)

Heavy Load Hours (HLH) are all those hours in the peak period hour ending 7 a.m. through the hour ending 10 p.m., Monday through Saturday, Pacific

Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable). BPA matches NERC Standards in classifying six holidays as Light Load Hours.

21. Inventory Augmentation (or Inventory Solution)

BPA's action to supplement the capability of the Federal System Resources, as a result of BPA's Subscription process.

22. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the off-peak period hour ending 11 p.m. through the hour ending 6 a.m., Monday through Saturday and all hours Sunday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable). BPA matches six holidays classified according to NERC Standards as LLH. Memorial Day, Labor Day and Thanksgiving occur on the same day each year: Memorial Day is the last Monday in May; Labor Day is the first Monday in September and Thanksgiving Day is the fourth Thursday in November. New Year's Day, Independence Day, and Christmas Day fall on predetermined dates each year. In the event that they fall on a Sunday, the holiday is celebrated the Monday immediately following that Sunday, so that Monday is also LLH all day. If these days fall on a Saturday, the holiday remains on that Saturday, and that Saturday is classified as LLH.

Cited in Pacific Northwest Generating v. DOE
No. 05-75638 archived on December 17, 2008

23. Measured Demand

The Purchaser's Measured Demand is that portion of its Metered or Scheduled Demand provided by BPA to the Purchaser. If more than one class of power is delivered to any point of delivery, the portion of the measured quantities assigned to any class of power shall be as specified by contract. Any delivery of Federal power not assigned to classes of power delivered under other agreements shall be included in the Measured Demand for PF, NR, or IP power as applicable.
The portion of the total Measured Demand so assigned shall constitute the Measured Demand for each such class of power. Any residual quantity, after determination of the Purchaser's contractual entitlement at a particular rate, is considered "unauthorized." Unauthorized increases are billed in accordance with the provisions of these GRSPs.

In determining Measured Demand for any Purchaser who experiences an outage as defined pursuant to the Purchaser's agreement with BPA, BPA shall adjust any abnormal Integrated Demand due to, or resulting from:

(a) emergencies or breakdowns on, or maintenance of, the Federal System Facilities; and

(b) emergencies on the Purchaser's facilities to the extent BPA determines that such facilities have been adequately maintained and prudently operated.

BPA will follow its billing process in establishing the Billing Demand should an outage cause an unusual Billing Demand quantity.

BPA will not give outage credits for demand.

24. Measured Energy

The Purchaser's Measured Energy is that portion of its Metered or Scheduled Energy that is provided by BPA to the Purchaser during a particular diurnal period (HLH or LLH) in a billing period. If more than one class of power is delivered to any point of delivery, the portion of the measured quantities assigned to any class of power shall be as specified by contract. Any delivery of Federal power not assigned to classes of power delivered under other agreements shall be included in the Measured Energy for PF, NR, or IP power as applicable. The portion of the total Measured Energy so assigned shall constitute the Measured Energy for each such class of power. Any residual quantity, after determination of the Purchaser's contractual entitlement at a particular rate, is considered "unauthorized." Unauthorized increases are billed in accordance with the provisions of these GRSPs.

Cited in Pacific Northwest Generating v. DOE
No. 05-75068 archived on December 17, 2008

25. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour Integrated Demands at which electric energy is delivered to a purchaser:

(a) at each point of delivery for which the Metered Demand is the basis for determination of the Measured Demand;

(b) during each time period specified in the applicable rate schedule; and

(c) during any billing period.

Such largest Integrated Demand shall be determined from measurements made in accordance with the provisions of the applicable contract and these GRSPs. This amount shall be adjusted as provided herein and in the applicable agreement between BPA and the Purchaser.

26. Metered Energy

The Metered Energy for a purchaser shall be the number of kWh that are recorded on the appropriate metering equipment, adjusted as specified in the applicable agreement and delivered to a Purchaser:

(a) at all points of delivery for which metered energy is the basis for determination of the Measured Energy; and

(b) during any billing period.

27. Monthly Federal System Peak Load

Monthly Federal System Peak Load is the peak load on the Federal System during a customer's billing month, determined by the largest hourly integrated demand produced from system generating plants in BPA's control area and scheduled imports for BPA's account from other control areas.

28. Net Billing Capacity Deficiency

Cited in Pacific Northwest Generating v. DOE, No. 05-73038 archived on December 17, 2008

A Net Billing Capacity Deficiency means as of the date of the Final ROD, the Administrator's forecast of purchases of power and transmission from BPA by a Net Billing Participant in any Net Billing Agreement Contact Year during the rate period, exceeds 110 percent of the Administrator's forecast of the aggregate charges by Energy Northwest in the related Net Billing Agreement Contract Year.

29. NP15

The portion of the CAISO control area north of transmission path 15.

30. NW1 (COB)

CAISO designation for delivery at COB (Captain Jack/Malin).

31. NW3 (NOB)

CAISO designation for delivery at NOB.

32. Partial Service Customer

A Partial Service customer is any customer that is not a Full Service customer.

33. Point of Delivery (POD)

A POD is the contractual interconnection point where power is delivered to the customer. Typically, a point of delivery is located at a substation site, but it could be located at the change of ownership point on a transmission line.

34. Point of Integration (POI)

A Point of Integration is the contractual interconnection point where power is received from the customer. Typically a point of integration is located at a

resource site, but it could be located at some other interconnection point to receive system power from the customer.

35. Point of Interconnection (POI)

A Point of Interconnection is a point where the facilities of two entities are interconnected.

36. Points of Metering (POM)

The POM shall be those points specified in the contract at which Total Retail Load and Metered Amounts are measured.

37. Pre-Subscription Contract

A contract for service in the FY 2002 through 2006 rate period that was signed prior to January 1, 1999, is a Pre-Subscription Contract.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

38. Purchaser

Pursuant to the terms of an agreement and applicable rate schedule(s), a Purchaser contracts to pay BPA for providing a product or service.

39. Receiving Party

The entity receiving the capacity and/or energy transmitted by BPA to a Point(s) of Delivery.

40. Retail Access

Retail Access is non-discriminatory retail distribution access mandated either by Federal or state law which grants retail electric power consumers the right to choose their electricity supplier.

41. Scheduled Demand

For purposes of applying the rates herein to applicable purchases by the Purchaser, the Scheduled Demand in kW is the largest of the hourly demands at which electric energy is scheduled by BPA for delivery to a purchaser:

(a) to each system for which Scheduled Demand is the basis for determination of the Measured Demand;

(b) during each time period specified in the applicable rate schedule; and

(c) during any billing period.

Scheduled Demand is deemed delivered for the purpose of determining Billing Demand.

42. Scheduled Energy

For purposes of applying the rates herein to applicable purchases by the Purchaser, Scheduled Energy in kWh shall be the sum of the hourly demands at which electric energy is scheduled by BPA for delivery to a purchaser:

(a) for each system for which Scheduled Energy is the basis for determination of the Measured Energy; and

(b) during any billing period.

Scheduled Energy is deemed delivered for the purpose of determining Billing Energy.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

43. Slice Revenue Requirement

The Slice Revenue Requirement is comprised of the items in BPA's PBL revenue requirement used to calculate the Slice product charge, as identified in the PBL's 2002 and 2007 Power rate cases. *See* Table 1, Slice Product Costing and True-Up Table.

44. Subscription

Subscription refers to the Power Subscription Strategy issued by BPA on December 21, 1998, which is BPA's policy for power sales beginning FY 2002.

45. Subscription Contract

Such power sales contract effective during the period between October 1, 2001, and September 30, 2011.

46. Total Plant Load (TPL)

Total Plant Load means a DSI customer's total electrical energy load at facilities eligible for BPA service during any given time period whether the customer has chosen to serve its load with BPA power or non-Federal power.

47. Total Retail Load (TRL)

Total Retail Load (TRL) is all electric power consumption including distribution system losses, within a utility's distribution system as measured at metering points, adjusted for unmetered loads or generation. No distinction is made

between load that is served with BPA power and load that is served with power from other sources. For DSIs, TRL is called Total Plant Load.

The TRL billing determinant for the Load Variance Charge will be adjusted for any load that is designated as exempt from the charge in accordance with the customer's Power Sales Agreement.

48. Utility Distribution Company (UDC)

A company that owns and maintains the distribution facilities used to serve end-use customers.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 Archived on December 17, 2008

Appendix A
2002 Slice Rate Methodology

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

APPENDIX A

2002 SLICE RATE METHODOLOGY

METHODOLOGY TO CALCULATE SLICE RATE AND SLICE TRUE-UP ADJUSTMENT CHARGE

Table 1: Slice Product Costing and True-Up Table begins on page 145.

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

METHODOLOGY TO CALCULATE SLICE RATE AND SLICE TRUE-UP ADJUSTMENT CHARGE

Section 1. PURPOSE

The Slice Methodology is designed as a means for providing a consistent method of calculating the rate for Slice and conducting the annual true-up for 10 years of the contract. Because there is some uncertainty regarding the calculation of the Slice rate in a rate period subsequent to the FY 2002-2006 rate period, the Slice Methodology is intended to bring some stability to the calculation of the rate. The Slice Methodology is not intended to predetermine the actual rate a Slice purchaser will pay in any rate period; rather, the Slice Methodology proposes a set of cost categories that will make up the Slice Revenue Requirement and the manner in which such costs may be trued up annually.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

Section 2. TERM OF THE METHODOLOGY

After FERC approval, this methodology shall take effect on October 1, 2001, and shall terminate on the earlier of midnight September 30, 2011, or a date established by FERC.

Section 3. DEFINITIONS

Actual Slice Revenue Requirement means the use of audited actual financial data in the cost categories comprising the Slice Revenue Requirement.

Capital Expenses means depreciation expense (recovery of the investment) and net interest expense (recovery of financing costs). Depreciation standards (*e.g.,* duration of useful life) used for the recovery of capital investments under the Slice contract will be the same as those used by BPA to set power rates generally, and will not change from those used in the development of Table 1, Slice Product Costing and True-Up Table, unless BPA adopts a new depreciation study.

Contracted Loads for each rate period shall be the average of the Fiscal Year (FY) loads for such rate period contracted for in annual aMW for the Public Agency customers, DSI customers to be served with FBS resources, IOU customers to be served with FBS resources, and the Preexisting Multiyear Contracts that are known to BPA.

Forecasted Loads for each rate period shall be the average of the forecasted FY loads for such rate period in annual aMW that was included in the applicable Final Power Rate Proposal for the Public Agency loads, DSI loads to be served with FBS resources, IOU loads served with FBS resources, and Preexisting Multiyear Contracts.

Initial Implementation Expenses means the expenses of implementing the Slice product for which BPA was reimbursed, prior to October 1, 2001, pursuant to the Master Agreement to Enable the Technical Development of a Slice of System Power Sale (Master Agreement).

Minimum Required Net Revenues means the amount by which BPA's payments to the U.S. Treasury for generation amortization and irrigation assistance exceed the total non-cash expenses in the Actual Slice Revenue Requirement.

Preexisting Multiyear Contracts means BPA's contracts for power sales, which have been executed as of June 21, 1999, with a term length that extends beyond the first year of the FY 2002-2006 rate period.

Slice Revenue Requirement means the operating and Capital Expenses and credits included in the Slice Rate which are established in the generation Revenue Requirement Study for the applicable rate periods and are subject to the criteria for inclusion of new costs or credits. The costs and credit categories included in the Slice Revenue Requirement are listed in Table 1, Slice Product Costing and True-Up Table.

Slice System Resources means the FBS resources identified in the Slice contract.

System Obligations means those operational or contractual obligations of the FBS that are identified in the Slice contract.

Cited in Pacific Northwest Generating v. DOE
No. 05-75638 archived on December 17, 2008

Section 4. METHODOLOGY

A. Slice Rate Calculation

The monthly rate for the Slice product will be calculated in the following manner:

Monthly rate for the Slice product per 1 percent of the Slice System = (Annual Average Slice Revenue Requirement / 12) /100 where the Slice Revenue Requirement is calculated as described in Section 4.B below. The monthly Expedited Bills for the Slice product will be adjusted by the application of the true-up of the Load-Based Cost Recovery Adjustment Clause (LB CRAC) for FY 2007.

For the FY 2007-2009 rate period, the Slice Revenue Requirement will contain the costs and credits estimated in the FY 2007 rate case for the cost and credit categories identified in Table 1, Slice Product Costing and True-Up Table, and any other currently unidentified cost or credit, as described in Section 4.B.3. below.

B. Slice Revenue Requirement

1. Uniform Application Throughout the Rate Period

The Slice Revenue Requirement is a three-year annual average amount for the applicable rate period. The Slice Rate will remain constant during the applicable rate period.

2. Cost and Credit Categories Used to Set the Slice Revenue Requirement

The cost and credit categories used to set the Slice Revenue Requirement and the Actual Slice Revenue Requirement shall be those defined in the generation Revenue Requirement Study for the 2002 Final Power Rate Proposal and listed in Table 1, Slice Product Costing and True-Up Table.

For FY 2002 only, the total of all Initial Implementation Expenses that BPA received under the Master Agreements shall be included in the Actual Slice Revenue Requirement.

3. Inclusion of New Costs or Credits

PBL costs or credits not otherwise specifically dealt with in the Slice Revenue Requirement, or excluded there from as specified in Section 4.B.4. below, may be included in both the Slice Revenue Requirement and the Actual Slice Revenue Requirement, if and to the extent that:

Such PBL costs or credits could be properly includable in PBL's wholesale power rates; and either

a. Such PBL costs or credits are: (1) incurred by PBL to provide service to customers other than Slice purchasers; and (2) incurred to provide service to or otherwise benefit Slice purchasers;

OR

b. Such PBL costs or credits are not incurred to provide service to customers other than Slice purchasers, nor to provide service to or otherwise benefit Slice purchasers.

Cited in Pacific Northwest Generating v. DOE, No. 05-75698 archived on December 17, 2008

4. Costs Excluded from the Slice Revenue Requirement

Excluded costs include, but are not limited to the following:

- All transmission costs (other than those associated with the transmission of System Obligations and GTAs);
- All power purchase costs (with the exception of net Inventory Solution costs);
- All PNRR and hedging costs, with the exception of those hedging costs incurred to implement the forecasted Inventory Solution; and
- All costs not permitted to be included in the Slice Revenue Requirement as specified by Section 4.B.3. above.

5. Credits

a. Systemwide Credits

Systemwide credits are any monetary credits that PBL forecasts to receive that are associated with the costs identified in the Slice Revenue Requirement. Systemwide credits shall be included in both the Slice

Revenue Requirement and the Actual Slice Revenue Requirement as a credit. The credits include, but are not limited to:

- Credits from the U.S. Treasury for PBL's settlement payment to the Colville Tribe;
- Credits from the U.S. Treasury for Section 4(h)(10)(c) of the Northwest Power Act;
- Credits from the U.S. Treasury for the FCCF; and
- Revenues BPA receives for meeting System Obligations (including revenues received for Congestion Management or PNCA transactions).

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

b. Transmission Surcharge

As provided for under separate rate and contract, BPA's TBL may impose a transmission surcharge on the Slice purchaser's use of the BPA transmission system. Any revenues received by the TBL pursuant to such surcharge will be credited to PBL's total Actual Slice Revenue Requirement, and will be reflected in the Slice purchaser's True-Up Adjustment. Repayment of such funds by the PBL to TBL, if any, shall be included in the Actual Slice Revenue Requirement.

c. Purchaser-Specific Credits and Other Contract Related Charges

All Slice purchaser-specific credits and other Slice purchaser-specific charges resulting from the implementation of the Slice contract shall be applied as an adjustment to the Slice True-Up Adjustment Charge for each specific Slice purchaser. The adjustment for credits and charges associated with the implementation of the Slice contract will be defined in the Slice contract.

6. Inapplicability of the Cost Recovery Adjustment Clause (CRAC), the National Marine Fisheries Service, Federal Columbia River Power System, Biological Opinion Adjustment (NFB Adjustment), the Emergency NFB Surcharge, the Targeted Adjustment Clause (TAC), and the Dividend Distribution Clause (DDC)

Neither the Slice Rate nor the Slice True-up Adjustment Charge paid by Slice purchasers will be subject to the CRAC, the NFB Adjustment, the Emergency NFB Surcharge, the TAC, or the DDC identified in the WP-07 GRSPs or any successor thereto.

7. Applicability of the Load-Based CRAC

For FY 2007, the LB CRAC true-up will apply to the Slice Expedited Bills.

8. Net Cost of the Inventory Solution

BPA has forecasted firm energy purchases that supplement the capability of FBS Resources (Inventory Solution) to meet the forecasted loads. The cost of the Inventory Solution shall be included in both the Slice Revenue Requirement and the Actual Slice Revenue Requirement on a net cost basis. The forecasted net cost of the Inventory Solution (NCIS) shall be calculated as: (1) the total expenses for the Inventory Solution; less (2) the total revenues for the sale of such power; both as projected by BPA. Since Slice purchasers bear the responsibility for their proportionate share of any loss of FBS resources or capability thereof, the Inventory Solution will not include such replacements. The forecasted net cost of the Inventory Solution to be included in the Slice Revenue Requirement for the FY 2007-2009 rate period is identified in Table 1.

Cited in Pacific Northwest Generating v. DOE, No. 05-75656 archived on December 17, 2008

C. Slice True-Up Adjustment Charge

The Slice True-Up Adjustment Charge is a monthly charge applied to the Slice product that is expressed in terms of dollars per percent Slice selected. The Slice True-Up Adjustment Charge consists of the Annual Slice True-Up Adjustment that is calculated once each fiscal year and is applied to specific months of the fiscal year. The Slice True-Up Adjustment Charge for each month shall be calculated in the following manner:

$STUAC_M = ASTU_M$

Where:

$STUAC_M$ is the Slice True-Up Adjustment Charge for month M of the rate period.

$ASTU_M$ is the portion of the Annual Slice True-Up Adjustment applicable for month M.

1. Annual Slice True-Up Adjustment

The Annual Slice True-Up Adjustment shall be calculated for each fiscal year as soon as independently audited actual financial data are available. As necessary, the Actual Slice Revenue Requirement shall include a Minimum Required Net Revenues component to ensure coverage of annual cash requirements. The Annual Slice True-Up Adjustment shall be calculated to be the annual Slice Revenue Requirement for the FY subtracted from the Actual Slice Revenue Requirement for such FY as shown in Table 1. The Annual Slice True-Up Adjustment shall be applied either as a one month credit (if the adjustment is negative) or as a three-month charge (if the adjustment is positive, and spread equally across the three months) following the month the Annual Slice True-Up Adjustment is calculated.

Table 1
Slice Product Costing and True-Up Table

($000s)

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

Cited in Pacific Northwest Generating v. DOE, No. 08-75638 archived on December 17, 2008

Table 1, continued
Slice Product Costing and True-Up Table

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

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 15, 2008

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

Appendix B
Load-Based Cost Recovery Adjustment Clause (LB CRAC) True-Up

This LB CRAC True-Up GRSP from the FY 2002-2006 rate period will carry over to FY 2007.

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

1. Load-Based Cost Recovery Adjustment Clause True-Up

(a) Application of the Load-Based Cost Recovery Adjustment Clause

The LB CRAC was a percentage rate adjustment based on BPA's cost of acquiring power to meet BPA's contractual obligations to serve loads in excess of the expected firm capability of the Federal Columbia River Power System (FCRPS) during the FY 2002-2006 rate period. To fulfill the intent of the LB CRAC procedures, a one time application of the LB CRAC True-Up is necessary. The True-Up for the last 6 months of the FY 2002-2006 rate period will be announced at a public workshop to be held in December 2006. The True-Up will be applied to 6 monthly bills, starting with first billing month beginning at least 15 working days after the determination of the True-Up.

Cited in Pacific Northwest Generating v. DOE, No. 05-75658 archived on December 17, 2008

The LB CRAC True-Up will be calculated only for FY 2006 and/or billed in FY 2007. The LB CRAC procedures listed here are copied from the FY 2002-2006 GRSPs. Definitions are to be interpreted using the FY 2002-2006 GRSPs. All terms and products included for this procedure are based on those used during the FY 2002-2006 rate period. Application of terms, products, and calculations included in this section are limited to LB CRAC True-Ups for FY 2006.

The LB CRAC was calculated and applied to the following rates for sales of energy, capacity, and load variance: PF [Preference, Exchange Program, and Exchange Subscription], Industrial Firm Power (IP-02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate, Residential Load (RL-02), New Resource Firm Power (NR-02), and Subscription purchases under Firm Power Products and Services (FPS), excluding revenues generated by the FB CRAC, SN CRAC, and distributions under Dividend Distribution Clause (DDC).

The LB CRAC was applied to the 1,000 average megawatts (aMW) power sale portion of the Residential Exchange Program (REP) Settlement, including where power sales are converted to cash payments calculated pursuant to Section 5(b) of the Residential Exchange Settlement Agreement. The LB CRAC also applies to the Priority Firm Slice Rate, excluding revenues from the contractual true-up pursuant to the Slice Agreement, and payments pursuant to Appendix A of these GRSPs.

The LB CRAC did not apply to power sales under Pre-Subscription contracts to the extent prohibited by such contracts, or to the 900 aMW of monetary benefits provided under the financial portion of the IOU REP Settlement, or to BPA's contractual obligations for Seasonal Irrigation Mitigation sales, including for any eligible customer that converts from Slice to another BPA product, and as a result, no LB CRAC True-Up will be applied to their bills.

These procedures are reprinted in their entirety; only those needed to complete the LB CRAC True-Up from FY 2006 are applicable.

(b) Definitions

(1) (AAMTA) "Augmentation Amount Actual" means the amount of actual augmentation required as determined in Section f (1) of these GRSPs.

(2) (AAMTF) "Augmentation Amount Forecast" means the forecasted augmentation as determined in Section d of these GRSPs.

(3) (ACTUALLBCREVREQ) "Actual LB CRAC Revenue Required" means an amount equal to the actual costs incurred by BPA to acquire AAMTA during any six-month period, and is equal to the sum of ACTUALLBCREVREQ(NS) [for Non-Slice products] and ACTUALLBCREVREQ(S) [for the Slice product].

Cited in Pacific Northwest Generating v. DOE, No. 05-75308 archived on December 17, 2008

(4) (ACTUALLBCREVREQ(NS)) "Actual LB CRAC Revenue Required (Non-Slice)" means the portion of the actual costs incurred by BPA to acquire AAMTA during any six-month period purchases apportioned to Non-Slice Rates.

(5) (ACTUALLBCREVREQ(S)) "Actual LB CRAC Revenue Required (Slice)" means the portion of the actual costs incurred by BPA to acquire AAMTA during any six-month period that is apportioned to Slice.

(6) (ADJUST(NS)) "Adjustment to a Purchaser's Non-Slice Monthly Bill" means the adjustment to a customer's monthly power bill for the purchase of energy, capacity and load variance products under Non-Slice Rates in an amount equal to one-sixth (1/6) of the customer's share of the Revenue Difference (REVDIFF[NS]) for the preceding six-month period.

(7) (ADJUST(S)) "Adjustment to a Purchaser's Slice Monthly Bill" means the adjustment to a customer's monthly power bill for purchases under Slice in an amount equal to the customer's share of REVDIFF(S) for the preceding six-month period.

(8) (APP) "Augmentation Pre–Purchase" means the quantity of power under a contract or other binding obligation entered into by BPA at least 120 days prior to the first day of the month for the delivery of AAMTF for a given month.

(9) (BUYDOWN) "Cost of Load Buydown" means the costs that BPA incurs to reduce or eliminate its contractual obligation to deliver firm power to regional customers and thereby lower the AAMTF or AAMTA for a month.

(10) (C&R (NS)) "Conservation and Renewables Discount–Non-Slice" means the total dollars actually credited to all Non-Slice purchasers under the Conservation & Renewable Discount.

(11) (C&R(S)) "Conservation and Renewables Discount–Slice" means the total dollars actually credited to all Slice purchasers under the Conservation & Renewables Discount.

(12) (CUSTREV(NS)) "Customer Revenue with LB CRAC–Non-Slice" means the actual revenues received by BPA from each customer for a given six-month period for the purchase of energy, capacity and load variance service at Non-Slice Rate subject to the LB CRAC, reduced by any C&R(NS) and LDD(NS).

(13) (CUSTREV(S)) "Customer Revenue with LB CRAC - Slice" means the actual revenues received by BPA from each customer for a given six-month period for purchases at the Slice rate subject to the LB CRAC, reduced by any C&R(S) and LDD(S).

Cited in Pacific Northwest Generating v. DOE, No. 05-75628 archived on December 17, 2008

(14) (DIURNALACA) "Actual Diurnal Augmentation Cost" means the diurnal cost, in dollars, actually incurred by BPA to acquire AAMTA. Diurnal costs are calculated using monthly flat AAMTA and the diurnal cost of acquiring that AAMTA.

(15) (DIURNALACF) "Diurnal Augmentation Cost Forecast" means the diurnal cost, in dollars, that BPA forecasts it will incur to acquire AAMTF. Diurnal costs are calculated using monthly flat AAMTF amounts and the diurnal cost of acquiring those AAMTF amounts.

(16) (LB CRAC %) "LB CRAC Percentage" means the percentage produced by dividing Net Augmentation Costs Forecasted (NACF) by Total Revenues without LB CRAC (TTREVw/oLBC).

(17) (LBCREV(NS)) "LB CRAC Revenues (Non-Slice) Received by BPA" means the amount of revenues actually received by BPA during any six-month period from the sale of energy, capacity and load variance services at Non-Slice Rates subject to the LB CRAC, as reduced by the C&R(NS) and LDD(NS).

(18) (LBCREV(S)) "LB CRAC Revenues [Slice] Received by BPA" means the amount of revenues actually received by BPA during any six-month period from sales at the Slice rate (WP-A-02, Section II.D.2), reduced by the C&R(S) and LDD(S).

(19) (LDD(NS)) "Low Density Discount Non-Slice" means the total dollars actually credited to all purchasers under Non-Slice Rates subject to the LB CRAC under the Low Density Discount.

(20) (LDD(S)) "Low Density Discount Slice" means the total dollars actually credited to all purchasers under the Slice rate under the Low Density Discount.

(21) (LOAD(NS)) "Non-Slice Load Subject to LB CRAC" means the loads that are served by BPA at Non-Slice Rate that are subject to the LB CRAC.

(22) (LOAD(S)) "Slice Load Subject to LB CRAC" means loads that are served by BPA at the Slice rate. LOAD[S] is to be (1,600/7,070)*100.

Cited in Pacific Northwest Generating v. DOE, No. 05-75028, archived on December 17, 2008

(23) (MARRA) "Monthly Augmentation Resale Revenues Actual" means the actual monthly resale revenues determined by multiplying the: (a) sum of: (i) Sales of Existing Augmentation Quantity (SALESMAYAUGA) multiplied by $28.10; and (ii) Sales of New Augmentation Quantity (SALESNEWAUGA) multiplied by $19.26; by (b) the number of hours in the month.

(24) (MARRF) "Monthly Augmentation Resale Revenues Forecasted" means the forecasted monthly resale revenues determined by multiplying the: (a) sum of: (i) Sales of Existing Augmentation Quantity (SALESMAYAUGF) multiplied by $28.10; and (ii) Sales of New Augmentation Quantity (SALESNEWAUGF) multiplied by $19.26; by (b) the number of hours in the month.

(25) (MSC) "Monthly System Capability" means the monthly value obtained by shaping the firm system capability to BPA's firm monthly loads, where firm system capability equals 7,070 aMW of FCRPS capability, less the amount of such capability sold to Slice purchasers. A separate shape will be produced for each separate year in the rate period. These monthly amounts of MSC are established once in the Supplemental Rate Case ROD.

(26) (NACA) "Net Augmentation Cost Actual" means the additional augmentation costs that are actually required to be recovered through application of the LB CRAC. NACA is determined separately for each month in any given six-month period.

(27) (NACF) "Net Augmentation Cost Forecast" means the forecast of additional augmentation costs that are required to be recovered through application of the LB CRAC. NACF is forecasted separately for each month in any given six-month period.

(28) (NACDIFF) "Net Augmentation Cost Difference" means the difference between NAC(120) and NAC(0).

(29) (NSL(A)) "Actual Non-Slice Load" means the actual amount of load served by BPA under Non-Slice Rates during a six-month period.

(30) (NSL(F)) "Forecasted Non-Slice Load" means the amount of load served by BPA during a six-month period under Non-Slice Rates.

(31) "Non-Slice Rates" means all BPA firm power rates, other than the PF Slice Rate and includes PF Preference, PF Exchange Program, PF Exchange Subscription, Industrial Firm Power, Industrial Firm Power Targeted Adjustment Charge and Industrial Firm Power Cost Based Index, Residential Load, New Resource Firm Power and the Firm Power Products and Services Rates.

Cited in Pacific Northwest Generating v. DOE, No. 05-75658 archived on December 17, 2008

(32) (OC) "Option Costs" means the costs actually incurred or revenues received by BPA by entering into physical or financial option contracts, or other financial contracts, or to reduce the cost of acquiring the cost of AAMTA or AAMTF.

(33) (PRICE) "Price For Forecasted Augmentation Amounts Not Pre-Purchased" means the forward price per megawatt-hour (MWh) used by BPA to determine the cost of purchasing power equal to the amount by which AAMTF exceeds APP. The PRICE will be established by BPA through the use of documented quotes for specific quantities from brokers or marketers or publicly available forward price indices. In each case, it is for electricity delivered at the Mid-Columbia market hub.

(34) (RATE(NS)) "Non-Slice Rates Without LB CRAC" means the Non-Slice rates established by BPA in May 2000 in the Administrator's Record of Decision in BPA Docket WP-02.

(35) (RATE(S)) "Slice Rate without LB CRAC" means the Slice rate established by BPA in May 2000 in the Administrator's Record of Decision in BPA Docket WP-02.

(36) (REVDIFF(NS)) "Revenue Difference Non-Slice" means the amount by which actual LBCREV(NS) exceeds or is less than ACTUALLBCREVREQ(NS) during any six-month period.

(37) (REVDIFF(S)) "Revenue Difference Slice" means the amount by which actual LBCREV(S) exceeds or is less than ACTUALLBCREVREQ(S) during any six-month period.

(38) (REVRATE(NS)) "Adjusted Non-Slice Rates" means the Non-Slice Rates that will apply to sales of energy, capacity and load variance products during the immediately upcoming six-month period.

(39) (REVRATE(S)) "Adjusted Slice Rate" means the Slice rate that will apply to sales of the Slice product during the immediately upcoming six-month period.

(40) (REVw/LBC(NS)) "Actual Non-Slice Revenues" means the monthly revenues actually received by BPA from sales of energy, capacity and load variance products during any six-month period, reduced by the C&R(NS) and LDD(NS).

(41) (REVw/LBC(S)) "Actual Slice Revenues" means the monthly revenues actually received by BPA from sales of the Slice product during any six-month period reduced by C&R(S) and LDD(S).

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

(42) (REVw/oLBC(NS)) "Baseline Non-Slice Revenues" means the monthly revenues received by BPA from sales of energy, capacity and load variance products subject to LB CRAC using RATE(NS) during any given six-month period reduced by the C&R(NS) and LDD(NS).

(43) (REVw/oLBC(S)) "Baseline Slice Revenues" means the monthly revenues received by BPA from sales of the Slice product during any given six-month period calculated using RATE(S), reduced by the C&R(S) and LDD(S).

(44) (SALESMAYAUGA) "Actual Sales of Existing Augmentation Quantity" means the resale of augmentation of 1,745 aMW minus [(actual DSI load/1486) * 450].

(45) (SALESMAYAUGF) "Forecasted Sales of Existing Augmentation Quantity" means the resale of augmentation of 1,745 aMW minus [(forecasted DSI load/1486) * 450].

(46) (SALESNEWAUGA) "Sales of New Augmentation Quantity Actual" means the actual monthly amount (in aMW) by which AAMTA is greater than the amount in SALEMAYAUGA.

(47) (SALESNEWAUGF) "Sales of New Augmentation Quantity Forecasted" means the forecasted monthly amount (in aMW) by which AAMTF is greater than the amount in SALEMAYAUGF.

(48) (TAUGCA) "Total Augmentation Cost Actual" means the sum of the monthly DIURNALACA, BUYDOWN and OC amounts for a given six-month period.

(49) (TAUGCF) "Total Augmentation Cost Forecast" means the sum of the monthly DIURNALACF, BUYDOWN, and OC amounts for a given six-month period.

(50) (TARRA) "Total Augmentation Resale Revenue Actual" means the sum of the separate monthly MARRA amounts for a given six-month period.

(51) (TARRF) "Total Augmentation Resale Revenue Forecasted" means the sum of the separate monthly MARRF amounts for a given six-month period.

(52) (TCAPPA) "Total Cost of Augmentation Pre-Purchases Actual Non-Slice" means the actual total cost to acquire APPA(NS).

(53) (TCAPPF) "Total Cost of Augmentation Pre-Purchases Forecasted" means the forecasted total cost of the APP made for a month.

(54) (TREVw/LBC(NS)) "Total Revenues for Non-Slice With LB CRAC" means the sum of all REVw/LBC(NS) for any given six-month period.

(55) (TREVw/LBC(S)) "Total Revenues for Slice with LB CRAC" means the sum of all REVw/LBC(S) for any given six-month period.

(56) (TTREVw/LBC) "Total Revenues with LB CRAC" means the sum of TREVw/LBC(S) and TREVw/LBC(NS).

(57) (TREVw/oLBC(NS)) "Total Non-Slice Revenues Without LB CRAC" means the sum of all REVw/oLBC(NS) for any given six-month period.

(58) (TREVw/oLBC(S)) "Total Slice Revenues without LB CRAC" means the sum of all REVw/oLBC(S) for any given six-month period.

(59) (TTREVw/oLBC) "Total Revenues without LB CRAC" means the sum of TREVw/oLBC(S) and TREVw/oLBC(NS).

(60) (TLA) "Transmission Loss Adjustment" means the Network loss factor adjustment applied under applicable BPA Transmission Business Line tariffs.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

(c) **Procedure**

Step One below addresses the calculations for determining the LB CRAC percentages that will apply to each six-month period. Step Two below addresses the determination of any rebate or surcharge due to actual LB CRAC exceeding or falling short of the actual costs incurred by BPA to acquire power after the end of the preceding six-month period. This section also describes the procedure by which BPA will provide public process on the application of the LB CRAC.

(1) Step One is calculation of the LB CRAC percentage and resulting adjustment to the rates that will be applied in each six-month period. On or about 90 days prior to the beginning of each six-month period (or in the case of the calculation of the LB CRAC to be applied for the period April 1 through September 30, 2002, on or about 45 days prior to the beginning of that second six-month period), BPA will establish the LB CRAC percentage and resulting adjustment to the rates that will apply to the sale of products under rates subject to the LB CRAC during upcoming six-month period. Using the process described in c(3) below, BPA will determine what data must be revised to develop the LB CRAC for the next six-month period. As a result of rate mitigation efforts, the Step One analysis will occur in two parts. This two-part process is designed to address the problem of some rate mitigation contracts containing pricing that is itself tied to the LB CRAC. For power buybacks made at a premium above the base rate plus the LB CRAC, in part one, BPA will: (a) include the premium portion of any such agreement; and (b) exclude the quantities of any such agreement from the calculation of REVw/LBC(S) and REVw/oLBC(NS). The increment in rates applicable to any such rate mitigation agreement from part one will then be added to the cost of meeting augmentation used in the calculation of the LB CRAC% in part two. Then, in part two the LB CRAC% and REVRATE will be determined. It is this set of adjusted rates that will appear on customer's bills.

Cited in Pacific Northwest Generating v. DOE, No. 05-73038 archived on December 17, 2008

(2) Step Two is the calculation of the amount by which actual LB CRAC revenues exceeded or fell short of the actual costs incurred by BPA to acquire power for the most recently concluded six-month period. As is described below, this calculation does not require a new calculation of the LB CRAC percentage or rates. The amount by which actual LB CRAC revenue exceeded or fell short of actual power costs will be established on or about 90 days after the end of the most recent six-month period. Any such excess or shortfall will be treated separately from any LB CRAC adjustment for the upcoming six-month period. A part of this determination involves revising data from that used to develop the LB CRAC in c(1) immediately above.

(3) Fifteen days prior to the date that BPA must establish the LB CRAC Percentage pursuant to paragraph c(1) above, and any charge or rebate for the amount of any excess or short-fall from the preceding six-month period, BPA will conduct a publicly noticed workshop. For the calculations to be performed for the first six-month period, BPA shall hold two workshops approximately 14 days apart, with the first workshop on or about June 6, 2001. The purpose of the workshop before a six-month period will be to provide customers with information used by BPA to develop the LB CRAC Percentage and adjusted rates for the next six-month period. The information used to perform these calculations will be provided to customers at a quarterly level of aggregation. The purpose of the workshop after a six-month period will be to determine any additional charge or rebate due individual customers for any excess or shortfall of actual LB CRAC revenue to cover NACA from the preceding six-month period. The information used to perform these calculations will be at a quarterly level of aggregation (including total and individual customer revenues used for such calculations). These workshops will provide customers with an opportunity to ask questions about BPA's calculations, and to provide BPA with information relevant to the calculation of the LB CRAC Percentage, adjusted rates, and any proposed charge or rebate.

Cited in Pacific Northwest Generating v. DOE No. 05-75638 archived on December 17, 2008

(d) Revenue and cost calculations performed before each six-month period

Before the six-month period, these calculations are performed with forecasted amounts to determine the LB CRAC Percentage and revised rates to be applied to purchaser bills during that period.

(1) Calculating AAMTF

This is a two-step process.

(A) Step One – Forecasted Non-Slice Loads (NSL(F))

In this step, BPA will determine what, if any, changes are required in the Forecasted Non-Slice loads contained in the Supplemental ROD.

(B) Step Two – Forecasted Augmentation Amount (AAMTF)

For each month separately, AAMTF = (NSL(F) – MSC) * (1 + TLA)

(2) Calculating the DIURNALACF

In this calculation, BPA establishes the costs it expects to incur to acquire AAMTF for each diurnal period for each month in the six-month period.

The following calculations will be separately performed for the HLH in a month and the LLH in each month in the next six-month period.

(A) If APP is greater than AAMTF,
DIURNALACF = (AAMTF/APP) * [TCAPPF]

(B) If APP is equal to AAMTF,

DIURNALACF = TCAPPF

(C) If APP is less than AAMTF,

DIURNALACF = [TCAPPF] + [(AAMTF-APP) *PRICE * Diurnal Hours]

Cited in Pacific Northwest Generating v. DOE, No. 05-75088 archived on December 17, 2008

(3) Calculating Total Augmentation Cost Forecast for a six-month period

BUYDOWN and OC obligations incurred as of the date of the forecast, and DIURNALCF monthly values for a six-month period will be summed to determine the Total Augmentation Cost Forecast (TAUGCF) for the six-month period.

TAUGCF = Sum of the six monthly (DIURNALACF + BUYDOWN + OC)

(4) Calculating Monthly and Total Augmentation Resale Revenues

This calculation establishes the resale revenue amount to be subtracted from TAUGCF for the six-month period.

The definitions of SALESMAYAUGF and SALESNEWAUGA for both the setting of the LB CRAC% and determining any credit or debit are modified to properly address the calculation of augmentation resale revenue to reflect rate mitigation.

SALESMAYAUGF = Minimum[AAMTF, (1,745 aMW – [(forecasted DSI load reduction/1486)*450])].

SALESNEWAUGF = MAX [0, AAMTF – SALESMAYAUGF]

MARRF = [(SALESMAYAUGF * $28.10) + (SALESNEWAUGF* $19.26)] * Hours in the month

TARRF = Sum of MARRF for each month in a six-month period

(5) Calculating Net Augmentation Cost Forecast for a six-month period

Once the TARRF is established, the NACF will be determined. This is the amount of forecasted costs that must be recovered in an LB CRAC mechanism.

NACF = TAUGCF - TARRF

(6) Calculating Monthly Revenues

This calculation determines the monthly revenues BPA receives from the sale of energy, capacity, and load variance products, including Slice, at rates that are subject to LB CRAC before the application of the LB CRAC.

Cited in Pacific Northwest Generating v. DOE
No. 05-75638 archived on December 17, 2008

<u>For the Slice rate</u>,

REVw/oLBC(S) = [RATE(S) * LOAD(S)] – LDD(S) – C&R(S)

Because the Slice rate is stated as $/% per month, REVw/oLBC(S), LOAD(S) is calculated using the percentage of Slice contracted, for example, 28.29% = 2,000 aMW of Slice. For Slice calculations, LDD(S) and C&R(S) are calculated as dollars. That is, LOAD(S) = (actual Slice load/7070)*100.

<u>For Non-Slice Rates for Part One:</u>

REVw/oLBC(NS) = [RATE(NS) * LOAD(NS) * Hours in month] – LDD(NS) – C&R(NS) – [the energy quantity of rate mitigation deals tied to LB CRAC from the Slice contracts * $27.5/MWh] – [the energy quantities of rate mitigation deals tied to LB CRAC from non-Slice contracts * $19.26/MWh]

<u>For Non-Slice Rates for Part Two:</u>

REVw/oLBC(NS) = [RATE(NS) * LOAD(NS) * Hours in month] – LDD(NS) – C&R(NS)

Because Non-Slice Rates are stated as $/MWh and $/kW-month, LOAD(NS) is expressed in MWh and kW for the month. LDD(NS) and C&R(NS) are values of the discounts in dollar amounts.

(7) Calculating Total Revenues without the LB CRAC for a six-month period

TREVw/oLBC(S) = ∑REVw/oLBC(S) for each month in six-month period.

TREVw/oLBC(NS) = ∑REVw/oLBC(NS) for each month in six-month period.

TTREVw/oLBC = TREVw/oLBC(S)+TREVw/oLBC(NS)

(e) Calculation of the LB CRAC percentage and revised rates for Slice and Non-Slice products

Calculations under this Section e only occur once in advance of each six-month period to make the adjustment that will apply to the upcoming six-month period. When the six-month period is over, the calculations in Section f are performed.

(1) Calculating the LB CRAC Percentage

LB CRAC% = NACF/TTREVw/oLBC

(2) Calculating the adjustment to RATE(NS) and RATE(S)

(A) Slice Rate

The spreadsheet model defines a variable Multiplier(S) which equals the bracketed term:

Multiplier (S) = {[((TREVw/oLBC(S) + LDD(S)) * LB CRAC%) + (TREVw/oLBC(S) + C&R(S) + LDD(S))]/[TREVw/oLBC(S) + C&R(S) + LDD(S)]}

REVRATE(S) = RATE(S) * Multiplier(S)

(B) Non-Slice Rates

The spreadsheet model defines a variable Multiplier(NS) which equals the bracketed term:

Multiplier (NS) = {[((TREVw/oLBC(NS) + LDD(NS)) * LB CRAC%) + (TREVw/oLBC(NS) + C&R(NS) + LDD(NS))]/[TREVw/oLBC(NS) + C&R(NS) + LDD(NS)]}

REVRATE(NS) = RATE(NS) * Multiplier(NS)

(3) Application of Revised Rates

The REVRATE(S) and REVRATE(NS) will replace the RATE(S) and RATE(NS), respectively, on purchaser's bills for products sold in the next six-month period that are subject to the LB CRAC.

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

(f) Calculations performed after the close of each six-month period

After the six-month period, these calculations are performed with actual amounts to determine the amount of any adjustment to individual customer bills as a result of an over or under collection of LB CRAC revenues.

(1) Calculating AAMTA

This is a two-step process.

(A) Step One – Actual non-Slice Loads (NSL(A))

In this step, BPA will determine the actual non-Slice loads.

(B) Step Two – Actual Augmentation Amount (AAMTA)

For each month separately, AAMTA = (NSL(A) – MSC) * (1+ TLA).

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

(2) Calculating DIURNALACA

In this calculation, BPA establishes the costs it actually did incur to acquire AAMTA for each diurnal period for each month in the six-month period.

The following calculations will be separately performed for the HLH in a month and the LLH in each month in the proceeding six-month period.

(A) If APP is greater than AAMTA,

DIURNALACA = (AAMTA/APP) * [TCAPPA]

(B) If APP is equal to AAMTA,

DIURNALACA = TCAPPA

(C) If APP is less than AAMTA,

DIURNALACA = [TCAPPA] + [(AAMTA-APP) * PRICE * Diurnal Hours]

(3) Calculating Total Augmentation Cost Actual for a six-month period

Once DIURNALACA, BUYDOWN, and OC are determined, these monthly values for a six-month period will be summed to determine the Total Augmentation Cost Actual (TAUGCA) for the six-month period.

TAUGCA = Sum of the six monthly (DIURNALACA + BUYDOWN + OC)

(4) Calculating Monthly and Total Augmentation Resale Revenues

This calculation establishes the resale revenue amount to be subtracted from TAUGCA for the six-month period.

SALESMAYAUGA = Minimum[AAMTA, (1,745 aMW – [(actual DSI load reduction/1486)*450])].

SALESNEWAUGA = MAX[0, AAMTA – SALESMAYAUGA]

MARRA = [(SALESMAYAUGA * $28.10) + (SALESNEWAUGA * $19.26)] * Hours in the month

TARRA = Sum of MARRA for each month in a six-month period

Cited in Pacific Northwest Generating v. DOE, No. 05-75638 archived on December 17, 2008

(5) Calculating Net Augmentation Cost Actual for a six-month period

Once the TARRA is established, the NACA will be determined. This is the actual costs that must be recovered in an LB CRAC mechanism.

NACA = TAUGCA - TARRA

(6) Calculating Monthly Revenues

(A) This calculation determines the monthly revenues BPA *would have* received from the sale of energy, capacity, and load variance products, including Slice, at rates that are subject to LB CRAC before the application of the LB CRAC, but using actual loads.

For the Slice rate,

REVw/oLBC(S) = [RATE(S) * LOAD(S)] – LDD(S) – C&R(S)

Because the Slice rate is stated as $/% per month, REVw/oLBC(S), LOAD(S) is calculated using the percentage of Slice contracted, for example, 28.29% = 2,000 aMW of Slice. That is, LOAD(S) = (actual Slice load/7070) * 100.

For Non-Slice rates,

REVw/oLBC(NS) = [RATE(NS) * LOAD(NS) * Hours in month] – LDD(NS) – C&R(NS)

Because Non-Slice rates are stated as mills/kWh and $/kW-month, LOAD(NS) is expressed in kWh and kW for the month.

(B) Calculating Actual Monthly Revenues received

This calculation determines the monthly revenues BPA *actually did* receive from the sale of energy, capacity, and load variance products, including Slice, at rates that are subject to LB CRAC *after* the application of the LB CRAC, but using actual loads.

For the Slice rate,

REVw/LBC(S) = [REVRATE(S) * LOAD(S)] – LDD(S) – C&R(S)

Cited in Pacific Northwest Generating v. DOE, No. 05-75038 archived on December 17, 2008

Because the Slice rate is stated as $/% per month, REVw/oLBC(S), LOAD(S) is calculated using the percentage of Slice contracted, for example, 28.29% = 2,000 aMW of Slice. That is, LOAD(S) = (actual Slice load/7070) * 100.

For Non-Slice rates,

REVw/LBC(NS) = [REVRATE(NS) * LOAD(NS) * Hours in month] – LDD(NS) – C&R(NS)

Because Non-Slice rates are stated as $/MWh and $/kW-month, LOAD(NS) is expressed in MWh and kW for the month.

(7) Calculating Total Revenues for a six-month period

(A) Without the LB CRAC applied

TREVw/oLBC(S) = ∑REVw/oLBC(S) for each month in six-month period.

TREVw/oLBC(NS) = ∑REVw/oLBC(NS) for each month in six-month period.

TTREVw/oLBC = TREVw/oLBC(S)+TREVw/oLBC(NS)

(B) With the LB CRAC applied

TREVw/LBC(S) = ∑REVw/LBC(S) for each month in six-month period.

TREVw/LBC(NS) = ∑REVw/LBC(NS) for each month in six-month period.

TTREVw/LBC = TREVw/LBC(S)+TREVw/LBC(NS)

(g) Determining the surcharge or rebate at the close of a six-month period

The calculations in this Section g are made once for each six-month period. They are applied only after a six-month period and are used to determine whether the costs incurred by BPA to acquire AAMTA during the preceding six-month period were more or less than the LB CRAC revenues actually received by BPA during such six-month period. The calculations in this Section will be performed as soon as the necessary actual data is available after each six-month period. There are four steps involved in this determination.

Cited in Pacific Northwest Generating v. DOE, No. 05-75698 archived on December 17, 2008

Step One: Calculate the LB CRAC revenues that were actually collected during the six-month period separately for Slice and Non-Slice sales;

Step Two: Calculate the LB CRAC revenues that are needed to cover the AAMTA power costs incurred by BPA during the six-month period, divided between Slice and Non-Slice products based on actual LB CRAC revenues;

Step Three: Calculate the difference between Step One and Step Two for Slice and Non-Slice products separately;

Step Four: Calculate the change in cost of meeting AAMTA associated with using the NACA(120) and NACA(0).

Step Five: Calculate the adjustment to the bill of each customer.

(1) Step One

LBCREV(S) = TREVw/LBC(S) – TREVw/oLBC(S)

LBCREV(NS) = TREVw/LBC(NS) – TREVw/oLBC(NS)

(2) Step Two

ACTUALLBCREVREQ(S) = [NACA * (TREVw/LBC(S)/TTREVw/LBC)]

ACTUALLBCREVREQ(NS) = [NACA * (TREVw/LBC(NS)/TTREVw/LBC)]

(3) Step Three

REVDIFF(S) = LBCREV(S) - ACTUALLBCREVREQ(S)

REVDIFF(NS) = LBCREV(NS) - ACTUALLBCREVREQ(NS)

(4) Step Four

In this step, the difference in cost associated with meeting AAMTA for the six-month period between NACA(0) and NACA(120) is determined. The difference will be referred to as:

NACDIFF = NACA(0) – NACA(120).

(5) Step Five

There will be a separate line item on the bill of each customer purchasing products at rates subject to the LB CRAC reflecting a debit or a credit, and referred to as ADJUST(S) for the Slice rate and ADJUST(NS) for Non-Slice Rates.

Cited in Pacific Northwest Generating v. BOP, No. 05-75008 archived on December 17, 2008

(A) Bill Adjustment for a Slice purchaser.

ADJUST(S) = {REVDIFF(S) * [CUSTREV(S)/TREVw/LBC(S)]}/6

(B) Bill Adjustment for Purchaser of Non-Slice products subject to the LB CRAC.

ADJUST(NS) = {[REVDIFF(NS) + NACDIFF] * [CUSTREV(NS)/TREVw/LBC(NS)]}/6

(C) Each of these bill adjustments (ADJUST(NS)) (ADJUST(S)) will initially be added to the bill beginning the month following their finalization and shall continue for a 6-month period. BPA and the purchaser may agree to a different payment schedule for any 6-month period. For the first 6-month period, since customers proposed two 3-month calculations, the results of the first 3-month calculation, scheduled for mid-February 2002, will be spread across 3 months, while the second 3-month adjustment, scheduled for June 2002, will be spread across 6 months (this assures no overlap between bill adjustments for the actual LB CRAC costs for this first six-month period).

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008

Cited in Pacific Northwest Generating v. DOE,
No. 05-75638 archived on December 17, 2008