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

2010 Wholesale Power and Transmission Rate Adjustment Proceeding (BPA-10)

ADMINISTRATOR'S FINAL RECORD OF DECISION

APPENDIX B

2010 Wholesale Power Rate Schedules (FY 2010-2011)
and
2010 General Rate Schedule Provisions (FY 2010-2011)

July 2009

WP-10-A-02-AP02

TR-10-A-02-AP02

BONNEVILLE POWER ADMINISTRATION

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BONNEVILLE POWER ADMINISTRATION
RATES
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COMMONLY USED ACRONYMS

AC	alternating current
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
ATC	Accrual to Cash
BAA	Balancing Authority Area
BASC	BPA Average System Cost
Bcf	billion cubic feet
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	combined-cycle combustion turbine
cfs	cubic feet per second
CGS	Columbia Generating Station
CHJ	Chief Joseph
C/M	consumers per mile of line ratio for LDD
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Conservation Rate Credit
CRFM	Columbia River Fish Mitigation
CRITFC	Columbia River Inter-Tribal Fish Commission
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DC	direct current
DDC	Dividend Distribution Clause
dec	decremental (pertains to generation movement)
DJ	Dow Jones
DO	Debt Optimization
DOE	Department of Energy
DOP	Debt Optimization Program

DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EAF	energy allocation factor
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc. (formerly Washington Public Power Supply System)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
F&O	financial and operating reports
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FELCC	firm energy load carrying capability
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	fiscal year (October through September)
GAAP	Generally Accepted Accounting Principles
GARD	Generation and Reserves Dispatch (computer model)
GCL	Grand Coulee
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	generator step-up transformers
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	heavy load hour
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydro Simulation (computer model)
IDC	interest during construction
inc	incremental (pertains to generation movement)
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRP	Integrated Resource Plan
ISD	incremental standard deviation
ISO	Independent System Operator
JDA	John Day
kaf	thousand (kilo) acre-feet

kcfs	thousand (kilo) cubic feet per second
K/I	kilowatthour per investment ratio for LDD
ksfd	thousand (kilo) second foot day
kV	kilovolt (1000 volts)
kVA	kilo volt-ampere (1000 volt-amperes)
kVAr	kilo-volt ampere reactive
kW	kilowatt (1000 watts)
kWh	kilowatthour
LDD	Low Density Discount
LGIP	Large Generator Interconnection Procedures
LLH	light load hour
LME	London Metal Exchange
LOLP	loss of load probability
LRA	Load Reduction Agreement
m/kWh	mills per kilowatthour
MAE	mean absolute error
Maf	million acre-feet
MCA	Marginal Cost Analysis
MCN	McNary
Mid-C	Mid-Columbia
MIP	Minimum Irrigation Pool
MMBtu	million British thermal units
MNR	Modified Net Revenues
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MOU	Memorandum of Understanding
MRNR	Minimum Required Net Revenue
MVA	mega-volt ampere
MVAr	mega-volt ampere reactive
MW	megawatt (1 million watts)
MWh	megawatthour
NCD	non-coincidental demand
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NIFC	Northwest Infrastructure Financing Corporation
NLSL	New Large Single Load
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries (officially National Marine Fisheries Service)
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPCC	Northwest Power and Conservation Council

NPV	net present value
NR	New Resource Firm Power (rate)
NT	Network Transmission
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OMB	Office of Management and Budget
OTC	Operating Transfer Capability
OY	operating year (August through July)
PDP	proportional draft points
PF	Priority Firm Power (rate)
PI	Plant Information
PMA	(Federal) Power Marketing Agency
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PS	BPA Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point to Point Transmission (rate)
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	U.S. Bureau of Reclamation
RD	Regional Dialogue
REC	Renewable Energy Certificate
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
RMS	Remote Metering System
RMSE	root-mean squared error
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTF	Regional Technical Forum
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition

SCCT	single-cycle combustion turbine
Slice	Slice of the System (product)
SME	subject matter expert
TAC	Targeted Adjustment Charge
TDA	The Dalles
Tcf	trillion cubic feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
UAI	Unauthorized Increase
UDC	utility distribution company
URC	Upper Rule Curve
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WPRDS	Wholesale Power Rate Development Study
WREGIS	Western Renewable Energy Generation Information System
WSPP	Western Systems Power Pool

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2010 WHOLESALE POWER RATE SCHEDULES

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2010 POWER RATE SCHEDULES

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SCHEDULE PF-10
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, 2009, and apply to purchases under Northwest Power Act section 5(b) requirements Firm Power sales contracts for a two-year period. The Slice Product is available for only public bodies and cooperatives that have signed Slice contracts for the FY 2002-2011 period. Utilities participating in the Residential Exchange Program under section 5(c) of the Northwest Power Act may purchase Priority Firm Power pursuant to a Residential Purchase and Sale Agreement. Rates under contracts that contain charges that escalate based on BPA's Priority Firm Power rates shall be based on the two-year rates listed in this rate schedule in addition to applicable transmission charges.

Effective October 1, 2009, this rate schedule supersedes the PF-07R rate schedule, which went into effect October 1, 2008. Sales under the PF-10 rate schedule are subject to BPA's 2010 General Rate Schedule Provisions (2010 GRSPs). Products available under this rate schedule are defined in BPA's 2010 GRSPs. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's 2010 GRSPs and billing process.

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

SECTION II. PF PREFERENCE RATE TABLES

The rates in this section apply to PF products as shown in Sections IV.A-G. The PF Exchange rate schedule is in Section III.

A. DEMAND RATE

1. Monthly Demand Rate for FY 2010 through FY 2011

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.

1.2 Rate Table

Applicable Months	*Monthly Rate*
January	$1.96 /kW
February	$1.99 /kW
March	$1.85 /kW
April	$1.74 /kW
May	$1.44 /kW
June	$1.32 /kW
July	$1.61 /kW
August	$1.89 /kW
September	$1.96 /kW
October	$2.05 /kW
November	$2.19 /kW
December	$2.30 /kW

B. ENERGY RATE

1. Monthly Energy Rates for FY 2010 through FY 2011

1.1 Applicability

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

1.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	29.68 mills/kWh	21.46 mills/kWh
February	30.31 mills/kWh	21.68 mills/kWh
March	28.12 mills/kWh	20.61 mills/kWh
April	26.39 mills/kWh	18.97 mills/kWh
May	22.04 mills/kWh	15.24 mills/kWh
June	19.95 mills/kWh	10.59 mills/kWh
July	24.57 mills/kWh	17.99 mills/kWh
August	28.78 mills/kWh	21.34 mills/kWh
September	29.70 mills/kWh	23.84 mills/kWh
October	31.41 mills/kWh	23.01 mills/kWh
November	33.50 mills/kWh	24.43 mills/kWh
December	34.96 mills/kWh	25.65 mills/kWh

C. LOAD VARIANCE RATE

The Load Variance Rate for FY 2010 through FY 2011 applies to all customers purchasing power under this rate schedule unless specifically excluded in Section IV below. The rate for Load Variance is 0.49 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 $1,962,525 per 1 percent of Slice.

SECTION III. PF EXCHANGE RATE TABLES

The rates in this section apply to PF products as shown in Section IV.H. The PF Preference rate schedule is in Section II.

A. ENERGY RATE

1. PF Exchange Energy Rates for FY 2010 through FY 2011

1.1 Applicability

These rates apply to utilities purchasing exchange power under Residential Purchase and Sale Agreements.

1.2 Base PF Exchange Rate

The Base PF Exchange rate applies to utilities purchasing exchange power and is subject to a utility-specific 7(b)(3) Supplemental Rate Charge, which is established specifically for each participating utility. The Base PF Exchange rate is 40.58 mills/kWh.

1.3 7(b)(3) Supplemental Rate Charge and PF Exchange Rate Table

	7(b)(3) Supplemental Rate Charge	Utility PF Exchange Rates
Avista	1.97 mills/kWh	42.55 mills/kWh
Idaho Power	0.00 mills/kWh	40.58 mills/kWh
Northwestern Energy	8.32 mills/kWh	48.90 mills/kWh
PacifiCorp	6.96 mills/kWh	47.54 mills/kWh
Portland General	7.34 mills/kWh	47.92 mills/kWh
Puget Sound Energy	8.03 mills/kWh	48.61 mills/kWh
Franklin County PUD	4.26 mills/kWh	44.84 mills/kWh
Snohomish County PUD No. 1	3.47 mills/kWh	44.05 mills/kWh

1.4 7(b)(3) Supplemental Rate Charge for Non-Listed Utilities

For eligible customers not listed in the PF Exchange Rate Table, the applicable 7(b)(3) Supplemental Rate Charge will equal the customer's Average System Cost minus the Base PF Exchange rate. The customer's Average System Cost will be determined pursuant to BPA's 2008 Average System Cost Methodology.

SECTION IV. BILLING FACTORS AND ADJUSTMENTS FOR EACH PF PRODUCT

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

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 monthly Demand Rate from Section II.A.

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 monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the monthly 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 2010 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2010 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
The NFB Mechanisms	II.G
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

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 monthly Demand Rate from Section II.A.

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 monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the monthly 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 2010 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2010 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Demand Adjuster	II.E
Dividend Distribution Clause	II.F
The NFB Mechanisms	II.G
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

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 monthly Demand Rate from Section II.A.

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 monthly HLH Energy Rate from Section II.B.

(2) The Purchaser’s LLH Energy Entitlement
as specified in the contract
multiplied by
the monthly 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 2010 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	*2010 GRSPs Section*
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Demand Adjuster	II.E
Dividend Distribution Clause	II.F
The NFB Mechanisms	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

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 monthly Demand Rate from Section II.A.

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 monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the monthly 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 2010 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2010 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
The NFB Mechanisms	II.G
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

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 monthly Demand Rate from Section II.A.

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 monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the monthly 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 2010 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2010 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Demand Adjuster	II.E
Dividend Distribution Clause	II.F
The NFB Mechanisms	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

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 monthly Demand Rate from Section II.A.

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 monthly HLH Energy Rate from Section II.B.

(2) The Purchaser’s LLH Energy Entitlement
as specified in the contract
multiplied by
the monthly 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 2010 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2010 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
The NFB Mechanisms	II.G
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

G. SLICE PRODUCT

Purchases of the Subscription Slice Product are limited to public body, cooperative, or Federal agency 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 (1% = .01)
multiplied by
100
multiplied by
the Slice Rate in Section II.D.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2010 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2010 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

H. PRIORITY FIRM EXCHANGE POWER

This PF Exchange rate applies to sales under a Residential Purchase and Sale Agreement (RPSA).

1. Priority Firm Exchange Power Charges

1.1 Demand Charge

No separate charge for demand.

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 as determined by BPA in accordance with the provisions of the Purchaser’s RPSA)
multiplied by
the Base PF Exchange rate plus the utility-specific 7(b)(3) Supplemental Rate Charge established specifically for each respective utility. See Section III.A.1.2.

1.3 Load Variance Charge

No additional charge.

2. Transmission Charges

Customers purchasing under this rate schedule are charged for transmission services at a rate based on the Network Transmission (NT) rate schedule or its successor. The Base PF Exchange rate in the Section III.A.1.2 Rate Table includes the transmission charge.

Customers purchasing under this rate schedule are charged for Load Regulation based on the applicable charge established by Transmission Services (TS) or its successor. The Base PF Exchange rate in the Section III.A.1.2 Rate Table includes the charge for Load Regulation.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2010 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2010 GRSPs Section***
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
The NFB Mechanisms	II.G
Low Density Discount	II.L
7(b)(3) Supplemental Rate Charge Adjustment	II.O

SECTION V. TRANSMISSION

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

SCHEDULE NR-10
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 investor-owned utilities under Northwest Power Act section 5(b) 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 used to serve any new large single load (NLSL), as defined by the Northwest Power Act. That portion of the utility's load served by BPA that is attributable to a NLSL will be billed under this rate schedule.

Rates in this schedule apply from October 1, 2009, through September 30, 2011, for purchasers of New Resource Firm Power. Products available under this rate schedule are defined in BPA's 2010 GRSPs.

Effective October 1, 2009, this rate schedule supersedes the NR-07R rate schedule, which went into effect October 1, 2008. Sales under the NR-10 rate schedule are subject to BPA's 2010 GRSPs and billing process.

SECTION II. NEW RESOURCE RATE TABLES

The rates in this section apply to NR products.

A. DEMAND RATE

1. Monthly Demand Rate for FY 2010 through FY 2011

1.1 Applicability

These rates apply to eligible customers purchasing Firm Power.

1.2 Rate Table

Applicable Months	***Monthly Rate***
January	$1.96 /kW
February	$1.99 /kW
March	$1.85 /kW
April	$1.74 /kW
May	$1.44 /kW
June	$1.32 /kW
July	$1.61 /kW
August	$1.89 /kW
September	$1.96 /kW
October	$2.05 /kW
November	$2.19 /kW
December	$2.30 /kW

B. ENERGY RATE

1. Monthly Energy Rates for FY 2010 through FY 2011

1.1 Applicability

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

1.2 Rate Table

Applicable Months	***HLH Rate***	***LLH Rate***
January	79.32 mills/kWh	66.49 mills/kWh
February	77.80 mills/kWh	65.44 mills/kWh
March	74.13 mills/kWh	62.03 mills/kWh
April	66.47 mills/kWh	55.60 mills/kWh
May	65.36 mills/kWh	45.98 mills/kWh
June	64.32 mills/kWh	48.04 mills/kWh
July	68.76 mills/kWh	59.12 mills/kWh
August	76.95 mills/kWh	64.76 mills/kWh
September	75.26 mills/kWh	66.54 mills/kWh
October	65.83 mills/kWh	55.71 mills/kWh
November	68.74 mills/kWh	61.02 mills/kWh
December	72.70 mills/kWh	64.22 mills/kWh

1.3 7(b)(3) Supplemental Rate Charge

Each energy rate in the Rate Table reflects a 7(b)(3) Supplemental Rate of 7.38 mills/kWh.

C. LOAD VARIANCE RATE

The Load Variance Rate for FY 2010 through FY 2011 applies to customers purchasing this product consistent with Section III below. The rate for Load Variance is 0.49 mill/kWh.

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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 and other loads served at the NR-10 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

A. NEW LARGE SINGLE LOAD (NLSL) SERVICE PRODUCT

Purchases of New Resource Firm Power to serve an 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 monthly Demand Rate from Section II.A.

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 monthly HLH Energy Rate from Section II.B.

(2) The NLSL's LLH Energy Entitlement as
specified in the contract
multiplied by
the monthly 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 2010 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	*2010 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
The NFB Mechanisms	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

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 monthly Demand Rate from Section II.A.

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 monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the monthly 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 2010 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2010 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
The NFB Mechanisms	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

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 monthly Demand Rate from Section II.A.

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 monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the monthly 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 2010 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2010 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Demand Adjuster	II.E
Dividend Distribution Clause	II.F
The NFB Mechanisms	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

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 monthly Demand Rate from Section II.A.

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 monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the monthly 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 2010 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2010 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Demand Adjuster	II.E
Dividend Distribution Clause	II.F
The NFB Mechanisms	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

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 monthly Demand Rate from Section II.A.

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 monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the monthly 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 2010 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2010 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
The NFB Mechanisms	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

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 monthly Demand Rate from Section II.A.

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 monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the monthly 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 2010 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2010 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Demand Adjuster	II.E
Dividend Distribution Clause	II.F
The NFB Mechanisms	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

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 monthly Demand Rate from Section II.A.

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 monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the monthly 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 2010 GRSPs. Relevant sections are identified below:

Adjustments, Charges, and Special Rate Provisions	***2010 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
The NFB Mechanisms	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

SECTION IV. TRANSMISSION

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

IP-10
INDUSTRIAL FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available to BPA's direct service industrial customers (DSIs), as defined by the Northwest Power Act, for Firm Power to be used in their industrial operations in the Pacific Northwest. Industrial Firm Power (IP) is available under Northwest Power Act section 5(d) to DSIs contracts for direct consumption.

Effective October 1, 2009, this rate schedule supersedes the IP-07R rate schedule, which went into effect October 1, 2008. Sales to DSI customers under the IP-10 rate schedule shall be subject to BPA's 2010 General Rate Schedule Provisions (GRSPs) and billing process. DSIs purchasing power pursuant to the IP-10 rate schedule shall be required to provide the Minimum DSI Operating Reserve – Supplemental.

SECTION II. INDUSTRIAL FIRM RATE TABLES

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

A. DEMAND RATE FOR ALL IP PRODUCTS

1. Monthly Demand Rate for FY 2010 through FY 2011

1.1 Applicability

These monthly rates apply to eligible customers purchasing Firm Power.

1.2 Rate Table

Applicable Months	***Monthly Rate***
January	$1.96 /kW
February	$1.99 /kW
March	$1.85 /kW
April	$1.74 /kW
May	$1.44 /kW
June	$1.32 /kW
July	$1.61 /kW
August	$1.89 /kW
September	$1.96 /kW
October	$2.05 /kW
November	$2.19 /kW
December	$2.30 /kW

B. ENERGY RATE

1. Monthly Energy Rates for FY 2010 through FY 2011

1.1 Applicability

These energy rates apply to eligible customers purchasing Firm Power.

1.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	38.46 mills/kWh	32.24 mills/kWh
February	37.72 mills/kWh	31.73 mills/kWh
March	35.94 mills/kWh	30.08 mills/kWh
April	32.23 mills/kWh	26.95 mills/kWh
May	31.69 mills/kWh	22.29 mills/kWh
June	31.18 mills/kWh	23.29 mills/kWh
July	33.33 mills/kWh	28.66 mills/kWh
August	37.31 mills/kWh	31.40 mills/kWh
September	36.49 mills/kWh	32.26 mills/kWh
October	31.92 mills/kWh	27.01 mills/kWh
November	33.33 mills/kWh	29.58 mills/kWh
December	35.24 mills/kWh	31.13 mills/kWh

1.3 7(b)(3) Supplemental Rate Charge

Each energy rate in the Rate Table reflects a 7(b)(3) Supplemental Rate Charge of 7.38 mills/kWh.

1.4 Value of Reserves Credit

Each energy rate in the Rate Table reflects a 0.80 mill/kWh credit for the value of the Minimum DSI Operating Reserve – Supplemental.

C. LOAD VARIANCE RATE

The Load Variance Rate for FY 2010 and FY 2011 applies to customers purchasing this product consistent with Section III below. The rate for Load Variance is 0.49 mill/kWh.

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SECTION III. BILLING FACTORS AND ADJUSTMENTS FOR EACH IP PRODUCT

This rate schedule contains two subsections, corresponding to the products to which this rate schedule applies. The following two products are available to serve loads at the IP-10 rate.

Section III.A. Block Product

Section III.B. Full Service Product

A. **BLOCK PRODUCT**

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

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 monthly Demand Rate from Section II.A.

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 monthly HLH Energy Rate from Section II.B.

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

1.3 Load Variance Charge

Load Variance is not applicable to Block Product purchases.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2010 GRSPs. Relevant sections are identified below:

Adjustments, Charges, and Special Rate Provisions	***2010 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
The NFB Mechanisms	II.G
Green Energy Premium	II.K
Unauthorized Increase Charge	II.Q
DSI Reserves Adjustment	II.S

B. FULL SERVICE PRODUCT

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

1. Industrial Firm Power

1.1 Demand Charge

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

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 monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the monthly 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 2010 GRSPs. Relevant sections are identified below:

Adjustments, Charges, and Special Rate Provisions	*2010 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
The NFB Mechanisms	II.G
Green Energy Premium	II.K
Unauthorized Increase Charge	II.Q
DSI Reserves Adjustment	II.S

SECTION IV. TRANSMISSION

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

FPS-10
FIRM POWER PRODUCTS AND SERVICES RATE

SECTION I. AVAILABILITY

This rate schedule is available for the purchase of Firm Power, Capacity Without Energy, Supplemental Control Area Services, Shaping Services, Reservation and Rights to Change Services, and Reassignment or Remarketing of Surplus Transmission Capacity for use inside and outside the Pacific Northwest during the period beginning October 1, 2009, and ending September 30, 2011.

Products and services available under this rate schedule are described in BPA's 2010 GRSPs. Sales under this rate schedule are discretionary: BPA is not obligated to sell any of these products, even if such sales will not displace PF/NR/IP sales. Ancillary Services needed for transmission service over Federal Columbia River Transmission System facilities shall be charged separately under the applicable transmission rate schedule.

Effective October 1, 2009, this rate schedule supersedes the FPS-07R rate schedule. Rates under contracts that contain charges that escalate based on rates listed in this rate schedule shall include applicable transmission charges. Sales under the FPS-10 rate schedule are subject to BPA's 2010 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 five 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

Section II.E. Reassignment or Remarketing of Surplus Transmission Capacity

A. FIRM POWER AND CAPACITY WITHOUT ENERGY

1. Flexible Rate

Demand and/or energy charges shall be as specified by BPA or 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.

2. 7(b)(3) Supplemental Rate Charge

A 7(b)(3) Supplemental Rate Charge of 7.38 mills/kWh shall be included in each FPS energy rate charge as determined pursuant to paragraph A.1 above. The inclusion of this 7(b)(3) Supplemental Rate Charge shall not inhibit the energy rate charge of the Flexible Rate from being either positive or negative.

3. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2010 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2010 GRSPs Section***
Cost Contributions	II.C
Unauthorized Increase Charge	II.Q
West-Wide Price Cap of FPS Sales	II.R

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 2010 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2010 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 2010 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2010 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 as 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.

E. REASSIGNMENT OR REMARKETING OF SURPLUS TRANSMISSION CAPACITY

Power Services may reassign or remarket surplus transmission capacity that it has reserved for its own use consistent with the terms of the transmission provider's Open Access Transmission Tariff (OATT).

1. Rates and Billing Factors

The charges for Reassignment or Remarketing of Surplus Transmission Capacity 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 Reassignment or Remarketing of Surplus Transmission Capacity shall be as established by BPA or as mutually agreed to by BPA and the Purchaser.

2. Adjustments, Charges, and Special Rate Provisions.

There are no additional adjustments, charges, or special rate provisions for the Reassignment or Remarketing of Surplus Transmission Capacity.

GTA-10
GENERAL TRANSFER AGREEMENT SERVICE RATE

SECTION I. GTA DELIVERY CHARGE

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

1. Rate and Billing Factor

The Rate and Billing Factor for the GTA Delivery Charge shall be the same as the Rate and Billing Factor for Transmission Services' Utility Delivery Charge.

SECTION II. TRANSFER SERVICE OPERATING RESERVE CHARGE

Power Services customers served by GTAs or other non-Federal transmission service agreements (hereafter “by transfer”) will be subject to the Transfer Service Operating Reserve Charge at such time that Transmission Services implements the WECC’s proposed reliability standard, BAL-002-WECC-1, regarding operating reserve (hereafter “the 3 and 3 reliability standard”). At such time, the Transfer Service Operating Reserve Charge will apply to power customers that meet the following criteria: (1) Power Services serves the customer by transfer; (2) the power customer does not pay Transmission Services for operating reserve based on the 3 and 3 reliability standard for the customer’s load; and (3) Power Services is assessed operating reserve charges by a third-party transmission provider for service to the power customer’s load.

1. Rate

a. The Transfer Service Spinning Operating Reserve Charge shall be equal to Transmission Services’ ACS-10 Operating Reserve – Spinning Reserve Service rate.

b. The Transfer Service Supplemental Operating Reserve Charge shall be equal to Transmission Services’ ACS-10 Operating Reserve – Supplemental Reserve Service rate.

2. Billing Factor

a. The monthly Billing Factor for the Transfer Service Spinning Operating Reserve Charge shall be the same as that used for the Transmission Services’ ACS-10 Operating Reserve – Spinning Reserve Service rate for load except that the load used to calculate the Billing Factor for Power Services’ charges will be the load of the customer served by transfer.

b. The monthly Billing Factor for the Transfer Service Supplemental Operating Reserve Charge shall be the same as that used for the Transmission Services’ ACS-10 Operating Reserve – Supplemental Reserve Service rate for load except that the load used to calculate the Billing Factor for Power Services’ charges will be the load of the customer served by transfer.

2010 GENERAL RATE SCHEDULE PROVISIONS

(GRSPs)

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2010 GENERAL RATE SCHEDULE PROVISIONS
(2010 GRSPs)

Subject **Page**

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2010 GENERAL RATE SCHEDULE PROVISIONS
(2010 GRSPs)

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

A. Approval of Rates

The Wholesale Power Rate Schedules and these General Rate Schedule Provisions (GRSPs) shall become effective upon interim approval or upon final confirmation and approval by the Federal Energy Regulatory Commission (FERC). BPA will request that FERC make these rates and GRSPs effective on October 1, 2009. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

The Wholesale Power Rate Schedules and these GRSPs associated with the schedules supersede BPA's 2007 Supplemental Wholesale Power Rate Schedules (FY 2009), which became effective October 1, 2008, to the extent stated in the Availability Section of each rate schedule. The schedules and these GRSPs shall be applicable to all BPA contracts, including contracts executed 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).

The rate schedules do not supersede any previously established rate schedule that 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 by 365 the applicable "Prime Rate" (reported in the "Money Rates" Section of the Wall Street Journal) plus 400 basis points. 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 GRSP 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. Supplemental Guidelines for Direct Assignment of Facilities Costs Incurred Under Transfer Agreements

BPA will use this set of Supplemental Guidelines to assign costs to Transfer Service customers. Such costs are comparable to the costs purchasers of Transfer Services would incur if such purchasers were directly connected to the BPA transmission system.

This set of Supplemental Guidelines augments the BPA Transmission Services "Guidelines for Direct Assignment Facilities," as amended or superseded (Transmission Services Guidelines), currently posted at:

http://www.transmission.bpa.gov/Business/Business_Practices/default.cfm

In determining whether to directly assign to a Transfer Customer costs incurred by BPA in providing transfer service to the customer, BPA will apply the current Transmission Services Guidelines and these Supplemental Guidelines. The Supplemental Guidelines apply only to transfer service acquired by BPA from third-party transmission providers for service to Preference Customers. The Supplemental Guidelines use some terms defined in the 20-year Agreement Regarding Transfer Service (ARTS). Also, Direct Assignment Facilities, as defined in most *pro forma* Open-Access Transmission Tariffs (OATT), are:

> Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer…

These Supplemental Guidelines are designed to supplement, not replace, the Transmission Service Guidelines and to assist in predicting how BPA, as the default transmission customer for transfer arrangements, will recover costs for Direct Assignment Facilities assessed by third-party transmission providers. Unless otherwise specifically excluded in the Transmission Services Guidelines or below, the cost of Direct Assignment Facilities will be passed through to the customer.

<u>Supplemental Guideline Regarding Voltages below 34.5 kV</u>

For new facilities or new service over existing third-party transmission provider facilities at voltages below 34.5 kV that meet the definition of Direct Assignment Facilities, metered quantities for customer deliveries will be adjusted for losses to the point where the voltage is at or above 34.5 kV, such that BPA is not responsible for losses across such facilities. Loss calculations should be similar whether the customer or the transmission provider owns the delivery facilities. **Note**: The cut-off voltage of 34.5 kV is used in the Transmission Services Guidelines. If this voltage level is changed in the Transmission Services Guidelines, these Supplemental Guidelines will be deemed modified.

Supplemental Guidelines Regarding Replacement with Higher Capacity Facility or Addition of a Transformer in Parallel

Pursuant to the Transmission Services Guidelines, for a new transmission provider-owned facility that also adds capacity, the costs that exceed the cost of replacing the previous capacity may be directly assigned to the benefiting customer. Alternatively, BPA and the customer may agree to full direct assignment in lieu of payment of the GTA Delivery Charge. Similarly, when a parallel transformer is added, BPA and the customer may agree to a simplified direct assignment of all delivery costs in lieu of some combination of Delivery Charge and direct assignment.

Supplemental Guidelines Regarding Construction Option

The customer may work directly with the third-party transmission provider to develop and select among options regarding construction, cost sharing, and ownership. BPA will work with the customer and the transmission provider to arrive at the best one-utility plan, workable cost-sharing options, equitable ownership, and interconnection arrangements. Due to regulatory issues, it is Power Services' policy not to own facilities.

Additional Guidelines:

Rolled-in Rate Treatment by Transmission Provider
If a customer receives new Transfer Service over new or pre-existing facilities below 34.5 kV offered by the transfer provider under a rolled-in rate or revenue requirement, BPA reserves the right to assess the GTA Delivery Charge. BPA will not assess the GTA Delivery Charge for a new point of delivery (POD) if specific facilities' costs are not rolled in but are directly assigned to BPA and in turn passed through to the customer.

Wholesale Distribution Facilities Beyond the Step-Down Substation
On any new arrangement for delivery below 34.5 kV (new or pre-existing facilities), the incremental cost for use of any facilities (other than potential transformers or current transformers for revenue metering) beyond the fence of the corresponding step-down transformer substation (or beyond a 20-foot radius of the step-down, for pole-top substations) shall be passed through to the customer, whether such costs are directly assigned to BPA or are imposed pursuant to a discrete wholesale distribution rate or Load Ratio Share of a discrete wholesale distribution revenue requirement.

Customer Arrangements Directly with the Third-Party Transmission Provider
A customer may, in lieu of paying the GTA Delivery Charge, choose to contract directly with the third-party transmission provider for delivery below 34.5 kV for an existing POD, but must then do so for all similar PODs with that transmission provider. The customer must take delivery from BPA at or above 34.5 kV for these PODs such that the customer is responsible for costs of and losses through the delivering facilities. A customer contracting with the third party for a new POD does not create a requirement that the customer contract with the third party for its pre-existing low voltage PODs.

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SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. Conservation Rate Credit (CRC)

1. Purpose and General Overview of the Conservation Rate Credit

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

(b) The CRC is set at 0.5 mills/kWh and is applied to eligible loads.

(c) Participants in the CRC will make investments in cost-effective conservation and qualifying renewable resource development in the region in a dollar amount equal to each customer’s eligible BPA loads times 0.5 mills/kWh.

(d) BPA will determine and publish lists of eligible measures and specific activities that, when implemented, satisfy customer obligations for the CRC.

(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 CRC Implementation Manual or its successor, to include reporting their accomplishments in the planning, tracking, and reporting (PTR) system.

2. Calculation of the Conservation Rate Credit

(a) Applicable Rate Schedules and Contracts. The CRC applies to loads served under the following:

(1) Priority Firm Power (PF-10) rate schedule (excluding the PF Exchange rate)

(2) Slice product under the PF-10 rate schedule

(3) New Resource Firm Power (NR-10) rate schedule

(4) Industrial Firm (IP-10) rate schedule (excluding aluminum DSIs)

(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 forecast average net requirements as established in the WP-10 Final Loads and Resources Study and Documentation, Chapters 2.2.1 and 2.2.2.

(2) Loads for individual Slice customers will be calculated using each customer's individual Slice percentage times 7070 aMW.

(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 by 24 the total forecast load for the FY 2010-2011 rate period determined in section 2(b). Then BPA will multiply each customer's average monthly load by 0.5 mills/kWh (*i.e.*, $0.0005/kWh) and round to the nearest whole dollar. This number is equal to the customer's rounded monthly CRC.

(2) The customer's annual CRC eligibility will be determined by multiplying by 12 the rounded monthly CRC calculated in section 2(c)(1).

(d) Applications of the Monthly Rate Credit

(1) The monthly CRC will be posted as a deduction on the customer's monthly power bill.

(2) When the monthly CRC is greater than the customer's other charges and credits, BPA may disburse the customer's credit balance in the form of a monthly check or electronic funds transfer in the amount that the customer's monthly CRC exceeds the customer's other charges and credits.

3. Reporting and Review of Individual Customers' CRC Activity

Customers must submit CRC reports into the PTR system documenting qualifying CRC expenditures, as required in the CRC Implementation Manual or its successor.

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

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

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

(3) Any customer electing not to receive the monthly CRC will be required to report to BPA total CRC-qualifying expenditures within 90 calendar days of BPA receipt of such customer's 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. make additional qualifying expenditures to reach its total accumulated monthly rate credit and report the expenditures to BPA within 120 calendar days of BPA receipt of the customer's 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 the customer's notice.

(b) Final Reconciliation Reports

(1) No later than 31 calendar days after the end of the rate period, by October 31, 2011, each customer shall submit to the designated BPA COTR for review a final reconciliation report summarizing the customer's total CRC-qualifying expenditures and total accumulated monthly CRC for the rate period.

(2) If a participating customer's final reconciliation report shows that the total accumulated monthly CRC 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, by November 30, 2011. If the customer's total CRC-qualifying expenditures still do not equal or exceed its total accumulated monthly CRC, the customer must reimburse the difference to BPA on or before March 31, 2012.

(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 accumulated monthly CRC received from BPA.

(5) BPA will not assess penalty charges on any reimbursement paid within the two-month window. However, any payment received after the due date (March 31, 2012) 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 the PF-10 (including Slice purchasers), IP-10, and NR-10 rate schedules.

C. Cost Contributions

Pursuant to section 7(j) of the Northwest Power Act, BPA has made the following resource cost determinations:

1. The forecast average cost of resources available to BPA under average water conditions is 35.46 mills/kWh.

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

Table A

	A	B	C	D
1	***Rate Schedule***	***Resource Cost Contribution***		
2		**Federal Base System**	**Exchange**	**New Resources**
3	PF	56.63%	43.37%	0%
4	IP	0%	83.98%	16.02%
5	NR	0%	83.98%	16.02%
6	FPS	0%	83.98%	16.02%

D. Cost Recovery Adjustment Clause (CRAC)

The CRAC is a downward adjustment to Residential Exchange Program (REP) benefits and an upward adjustment to HLH and LLH Energy and Load Variance rates for sales under these Firm Power rate schedules:

- Priority Firm Preference (PF-10), excluding the PF Slice Product
- Industrial Firm Power (IP-10)
- New Resource Firm Power (NR-10)
- BPA's contractual obligations for Irrigation Rate Mitigation Product sales

The CRAC does not apply to:

- sales under the PF Slice Product
- power sales under Pre-Subscription contracts to the extent prohibited by such contracts
- Demand sales (unless a trigger event under the NFB Adjustment increases the CRAC cap and the CRAC triggers for an amount greater than the original cap, in which case the amount of CRAC revenue in excess of the original cap will be collected through an increase to all Demand, Energy, and Load Variance rates proportionately)

1. Calculations for the Cost Recovery Adjustment Clause

Prior to the beginning of each fiscal year of the rate period, BPA will forecast the end-of-year AMNR for the preceding fiscal year. If the forecast AMNR is less than the CRAC Threshold for that fiscal year, the CRAC will trigger, and a rate increase and REP benefit decrease will go into effect beginning on October 1 of the upcoming fiscal year.

(a) Calculating the CRAC Amount

The CRAC Amount is the lower of:

CRAC Threshold minus forecast AMNR

or

Maximum CRAC Recovery Amount (Cap), shown in Table B below.

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

	A	B	C	D	E
1	**AMNR Calculated at End of Fiscal Year**	**CRAC Applied to Fiscal Year**	**CRAC Threshold Measured in AMNR**	**Approx. Threshold as Measured in Power Services Reserves**	**Maximum CRAC Recovery Amount (Cap)***
2	2009	2010	-$876.5	$0	$300
3	2010	2011	-$790.7	$0	$300

* The Maximum CRAC Recovery Amount (Cap) may be modified by the NFB Adjustment (if triggered).

Where *CRAC Amount* is the additional net revenue that an increase in rates, due to the CRAC, is intended to generate during the year of application.

Where *CRAC Threshold* is the “trigger point” for invoking a rate increase and REP benefit decrease under the CRAC.

Where *AMNR* is Accumulated Modified Net Revenues for the generation function, as accumulated since 1999. The forecast of AMNR is used to determine whether the CRAC Threshold has been reached, and if so, the required CRAC Amount to be collected. The forecast of AMNR will be calculated by determining the accumulated annual Modified Net Revenue (MNR) beginning October 1, 1999, through the end of the current fiscal year.

Where *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). (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 exclude actual Energy Northwest (EN) debt service but will include forecast EN debt service

identified in the Final Proposal for the most recent rate proceeding applying to that year.

(3) The forecast of MNR for the current fiscal year will be based on actual generation function revenues and expenses for the first three quarters of the year and forecast 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. Transmission function accrued revenues and expenses are excluded. The MNR includes impacts on forecast revenues, positive or negative, from contractual true-ups 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) Calculating the PF/IP CRAC Amount and the REP CRAC Amount

The PF/IP CRAC Amount is 0.802 times the CRAC Amount.

The REP CRAC Amount is 0.278 times the CRAC Amount.

(c) Converting the PF/IP CRAC Amount to the CRAC Percentage

Once the PF/IP CRAC Amount is determined, that amount will be converted to a percentage increase applied to applicable HLH and LLH Energy and Load Variance rates:

(1) The CRAC Percentage is calculated by dividing the PF/IP CRAC Amount by the most current forecast of HLH, LLH, and Load Variance revenues from products subject to the CRAC.

(2) The CRAC Percentage will be applied to HLH and LLH Energy rates and the Load Variance rate for the 12 months of the relevant fiscal year for products subject to the CRAC.

(d) CRAC Percentages After an NFB Adjustment

If the CRAC Cap has been increased by an NFB Adjustment, and the CRAC Amount is larger than the original CRAC Cap in Table B, two CRAC Percentages will be calculated:

The PF/IP CRAC1 Amount is 0.802 times the CRAC Cap from Table B

The PF/IP CRAC2 Amount is 0.802 times the difference between the CRAC Amount and the CRAC Cap from Table B.

(1) The CRAC1 Percentage is calculated by dividing the PF/IP CRAC1 Amount by the most current forecast of HLH, LLH, and Load Variance revenues from products subject to the CRAC.

(2) The CRAC1 Percentage will be applied to HLH and LLH Energy rates and the Load Variance rate for the 12 months of the relevant fiscal year for products subject to the CRAC.

(3) The CRAC2 Percentage is calculated by dividing the PF/IP CRAC2 Amount by the most current forecast of HLH, LLH, Load Variance, and Demand revenues from products subject to the CRAC.

(4) The CRAC2 Percentage will be applied to HLH and LLH Energy rates, the Load Variance rate, and the Demand rate for the 12 months of the relevant fiscal year for products subject to the CRAC.

(e) Adjusting the REP Benefits

Total REP benefits will be reduced by the REP CRAC Amount, as shown in Section II.O.1 of these GRSPs. The 7(b)(3) Supplemental Rate Charges will then be recalculated using the REP benefits as revised by application of the CRAC.

2. CRAC Adjustment Timing

Prior to the beginning of each fiscal year, the Administrator will determine whether the AMNR forecast for the end of that year is below the CRAC Threshold and whether a CRAC rate adjustment is needed for the next fiscal year.

(a) CRAC Notification Process

BPA shall follow these notification procedures:

(1) Financial Performance Status Reports

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

For the Second and Third Quarter Reviews, BPA shall post to its external Web site (www.bpa.gov) the preliminary, unaudited *end-of-year* forecast of AMNR attributable to the generation function.

(2) Notification of CRAC Trigger

BPA shall complete a forecast of end-of-year AMNR in early September prior to each fiscal year in the rate period. If the forecast value of AMNR falls below the Threshold for the CRAC applicable to the following year, then BPA shall notify all customers and rate case parties in early September each year. BPA shall notify customers and rate case parties by late September of the amount by which BPA intends to adjust rates and REP benefits due to the CRAC. Notification will be posted on BPA's Web site and will include the audited AMNR for the previous fiscal year, the forecast of end-of-year AMNR for the current fiscal year, the CRAC Amount, the REP CRAC Amount, the PF CRAC Amount, and the CRAC Percentage for the subsequent fiscal year. The notification shall also describe the data and assumptions relied upon by BPA for the AMNR determination. BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

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

The Administrator may elect at his or her discretion to reduce the CRAC rate adjustment as long as the resulting TPP for the remainder of the rate period is greater than or equal to BPA's TPP standard (95 percent for the FY 2010-2011 period in the case of the 2010 CRAC; 97.5 percent for FY 2011 in the case of the 2011 CRAC). In the case of the CRAC applicable to the FY 2010 rates, the Administrator may modify the parameters for the CRAC applicable to FY 2011 rates to meet the one-year TPP standard for FY 2011. If the Administrator so elects, s/he shall inform the customers of this decision during the workshop.

On or about September 30 of any fiscal year in which the CRAC triggers, BPA will post to the BPA Web site the final calculation of the CRAC Percentage adjustment to each product and the dollar adjustment to each exchanging utility's REP benefits. The CRAC Percentage will include any NFB Adjustment (see Section II.G) to the CRAC Cap.

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 and is calculated by dividing the customer's Total Retail Load at the time of the GSP by the customer's Total Retail Load on its own 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 an upward adjustment to REP benefits and a downward adjustment to HLH and LLH Energy and Load Variance rates for sales under these Firm Power rate schedules:

- PF-10 Preference, excluding the PF Slice Product
- Industrial Firm Power (IP-10)
- New Resource Firm Power (NR-10)
- BPA's contractual obligations for Irrigation Rate Mitigation Product sales

The DDC does not apply to:

- sales under the PF Slice Product
- power sales under Pre-Subscription 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, BPA will forecast the end-of-year AMNR for the preceding fiscal year. If the forecast AMNR is greater than the DDC Threshold for that fiscal year, the DDC will trigger, and a rate decrease and REP benefit increase will go into effect beginning on October 1 of the upcoming fiscal year.

(a) Calculating the DDC Amount

The DDC Amount =

Forecast AMNR minus DDC Threshold

Table C: DDC Thresholds
[Dollars in Millions]

	A	B	C	D
1	**AMNR Calculated at End of Fiscal Year**	**DDC Applied to Fiscal Year**	**DDC Threshold Measured in AMNR**	**Approx. Threshold as Measured in Power Services Reserves**
2	2009	2010	-$126.5	$750
3	2010	2011	-$40.7	$750

Where *DDC Amount* is the reduction in modified net revenues that a decrease in rates, due to the DDC, is intended to generate during the year of application.

Where *DDC Threshold* is the “trigger point” for invoking a rate decrease and REP benefit increase under the DDC.

Where *AMNR* is accumulated modified net revenues for the generation function, as accumulated since FY 1999. The forecast of AMNR is used to determine whether the DDC Threshold has been reached, and if so, the required Distribution Amount to be distributed. The forecast of AMNR will be calculated by determining the accumulated annual MNR beginning October 1, 1999, through the end of the current fiscal year.

Where *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). (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 exclude actual Energy Northwest debt service but will include forecast EN debt service identified in the Final Proposal for the most recent rate proceeding applying to that year.

(3) The forecast of MNR for the current fiscal year will be based on actual generation function revenues and expenses for the first three quarters of the year and forecast 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 forecast revenues, positive or negative, from contractual true-up pursuant to the Slice Agreement.

(b) Calculating the PF/IP DDC Amount and the REP DDC Amount

The PF/IP DDC Amount is 0.802 times the DDC Amount.

The REP DDC Amount is 0.278 times the DDC Amount.

(c) Converting the PF/IP DDC Amount to the DDC Percentage

Once the PF/IP DDC Amount is determined, that amount will be converted to a percentage decrease applied to applicable HLH and LLH Energy rates and Load Variance rates. The DDC Percentage will be applied as follows:

(1) The DDC Percentage is calculated by dividing the PF/IP DDC Amount by the most current forecast of HLH, LLH, and Load Variance revenues from products eligible for the DDC. The DDC Percentage is limited to (*i.e.,* is capped by) the percentage that would reduce the LLH energy rate below 1 mill/kWh. If this cap reduces the amount of the PF/IP DDC Amount that can be distributed, the REP DDC Amount will be reduced proportionately.

(2) The DDC Percentage will be applied to HLH and LLH Energy rates and the Load Variance rate for the 12 months of the relevant fiscal year for products eligible for the DDC.

(d) Adjusting the REP Benefits

Total REP benefits will be increased by the REP DDC Amount, as shown in Section II.O.1 of these GRSPs. The 7(b)(3) Supplemental Rate Charges will then be recalculated using the REP benefits as revised by application of the DDC.

2. DDC Adjustment Timing

Prior to the beginning of each fiscal year, the Administrator will determine whether the AMNR forecast for the end of that year is above the DDC Threshold and whether a dividend distribution adjustment is needed for the next fiscal year.

(a) DDC Notification Process

BPA shall follow these notification procedures:

(1) Financial Performance Status Reports

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

For the Second and Third Quarter Reviews, BPA shall post to its external Web site (www.bpa.gov) the preliminary, unaudited *end-of-year* forecast of AMNR attributable to the generation function.

(2) Notification of DDC Trigger

BPA shall complete a forecast of end-of-year AMNR in early September prior to each fiscal year in the rate period. If the forecast value of AMNR is above the Threshold for the DDC applicable to the following year, then BPA shall notify all customers and rate case parties by early September each year. BPA shall notify customers and rate case parties by late September of the amount by which BPA intends to adjust rates and REP benefits due to the DDC. Notification will be posted on BPA's Web site and will include the audited AMNR for the previous fiscal year, the forecast of end-of-year AMNR for the current fiscal year, the DDC Amount, the REP DDC Amount, the PF DDC Amount, and the DDC Percentage for the subsequent fiscal year. The notification shall also describe the data and assumptions relied upon by BPA for the AMNR determination. BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

In September of any year in which AMNR is forecast to be above the DDC Threshold for the DDC applicable to the next fiscal year, BPA staff shall conduct a workshop(s) to explain the AMNR forecast, describe the calculation of the DDC Amount and the DDC Percentage, and demonstrate that the DDC has been implemented in accordance with these GRSPs. The workshop(s) will provide an opportunity for public comment.

On or about September 30 of any fiscal year in which the DDC triggers, BPA will post to the BPA Web site the final calculation of the DDC Percentage adjustment to each product and the dollar adjustment to each exchanging utility's REP benefits.

G. The NFB Mechanisms

The two NFB mechanisms described here are rate features that allow BPA to recover additional revenue if financial impacts ("Financial Effects") from a specified set of circumstances ("Trigger Events") in the fish and wildlife arena cause a reduction in Power Services' forecast MNR. The first mechanism, the NFB Adjustment, can result in an increase in the Cap for the CRAC applicable to the fiscal year(s) following the fiscal year in which an NFB Trigger Event (see below) occurs. The second mechanism, the Emergency NFB Surcharge, can result in a rate increase and REP benefit decrease within the fiscal year in which an NFB Trigger Event resulting in Financial Effects occurs. The latter situation would apply if waiting until the next year for additional cost recovery would be imprudent because BPA is in a "cash crunch" (defined in the subsection on the Emergency NFB Surcharge below).

1. Definitions

(a) An *NFB Trigger* Event is one of the following four kinds of events that results in changes to BPA's FCRPS Endangered Species Act (ESA) obligations compared to those adopted in the most recent wholesale power rate proceeding as modified prior to this Trigger Event:

(1) A court order in *National Wildlife Federation vs. National Marine Fisheries Service*, CV 01-640-RE, or any other case filed regarding an FCRPS Biological Opinion (BiOp) issued by NMFS (now known as the NOAA Fisheries Service), 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 FCRPS BiOp.

(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 net reductions in estimated Power MNR within the fiscal year 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, COE and Reclamation O&M expenses, or amortization of capital costs when compared with the estimate of the foregoing revenues, credits, costs, and obligations adopted in the most recent wholesale power rate proceeding, as modified prior to this Trigger Event. These effects are the total effects on the BPA System, excluding the operational or expense effects borne directly by Slice Customers.

(c) The *Agency Within-Year TPP* is the probability that the Agency (including 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 occurs. Agency Within-Year TPP 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, any 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-10 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.

(d) *Surcharge Amount* is the amount of money to be collected under the Emergency NFB Surcharge.

(e) *Revenue Basis* is the 12-month totals of revenue from Firm Power sales subject to the Emergency NFB Surcharge for a specific fiscal year.

(f) *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. The NFB Adjustment

The NFB Adjustment results in an upward adjustment to the CRAC Cap for a fiscal year in the rate period if Financial Effects from an NFB Trigger Event(s) occur. For the WP-10 rates, the NFB Adjustment calculation can result in an increase in the annual CRAC Cap defined in Table B for FY 2010 if an NFB Trigger Event occurs in FY 2009, or for FY 2011 if an NFB Trigger Event occurs in FY 2009 or FY 2010.

If the CRAC triggers for a year for which the CRAC Cap has been increased by an NFB Adjustment, then the PF portion of CRAC Amounts in excess of the caps shown in Table B will be proportionally collected from LLH and HLH Energy, Load Variance, and Demand rates for sales under the Firm Power rate schedules subject to the CRAC.

NFB Adjustment = Financial Effects of Trigger Event(s)

Adjusted CRAC Cap = CRAC Cap from Table B + NFB Adjustment

3. The Emergency NFB Surcharge

The Emergency NFB Surcharge (Surcharge) results in an upward adjustment to specified Power rates and reductions in REP benefits during a year in which (a) Financial Effect(s) occur from a Trigger Event(s) and (b) the Agency Within-Year TPP is below 80 percent as described in section 4, below (also referred to as a "cash crunch"). The Emergency NFB Surcharge is a separate adjustment from the NFB Adjustment.

The Surcharge addresses the fact that the CRAC does not increase revenues until the fiscal year following the fiscal year in which Financial Effects of a Trigger Event are experienced. Thus, the financial benefit of the NFB Adjustment may be too late if BPA is in a cash crunch when a Trigger Event occurs. For the WP-10 rates, the Surcharge may be implemented in FY 2010 if the (a) and (b) events required to impose the Surcharge occur in that fiscal year, or in FY 2011 if the requisite (a) and (b) events occur in that year.

The Surcharge is a downward adjustment to REP benefits and an upward adjustment to HLH and LLH Energy and Load Variance rates for sales under these Firm Power rate schedules:

- PF-10 Preference, excluding the PF Slice Product
- Industrial Firm Power (IP-10)
- New Resource Firm Power (NR-10)
- BPA's contractual obligations for Irrigation Rate Mitigation Product sales.

The Surcharge does not apply to:

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

Surcharge Amount = Financial Effects of Trigger Event

PF/IP Surcharge Amount is 0.802 times the Surcharge Amount.

REP Surcharge Amount is 0.278 times the Surcharge Amount.

Each Customer Percentage will be multiplied by the PF/IP Surcharge Amount and the result divided by the number of billing months payable before the end of the then-current fiscal year to determine each customer's Monthly Surcharge. The Monthly Surcharge will be added to each customer's bill for each billing month payable before the end of the current fiscal year.

Total REP benefits will be reduced by the REP Surcharge Amount, as shown in Section II.O.1 of these GRSPs. The annual reduction will be divided by the number of billing months payable before the end of the then-current fiscal year to determine the total reduction in REP benefits. The 7(b)(3) Supplemental Rate Charges will then be recalculated using the REP benefits as revised by application of the Surcharge.

There can be more than one Trigger Event in a year, and therefore there could be more than one Surcharge implemented in a fiscal year.

At the discretion of the Administrator, BPA may collect the Surcharge Amount by modifying the Monthly Surcharge to collect less in earlier months and more in later months of the 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. If either of these conditions results in Surcharge revenues totaling less than the total Financial Effects for Trigger Events in a year, the remaining balance of Financial Effects will result in an NFB Adjustment to the CRAC Cap for the subsequent year.

4. Criteria for Applying the NFB Adjustment or Assessing the Surcharge

NFB Trigger Events that have Financial Effects can lead to NFB Adjustments or Surcharges according to these GRSPs if they occur in fiscal years 2009, 2010, or 2011. Whether such Trigger Events lead to NFB Adjustments or to Surcharges depends on whether BPA is in a "cash crunch" in the year in which the Trigger Event occurs. A "cash crunch" means the Agency Within-Year TPP is calculated to be below 80 percent including (1) the Financial Effects of all Trigger Events and (2) all revenues from those, but only those, CRACs and Emergency NFB Surcharges that have already been implemented (*i.e.*, calculated, and scheduled to be affecting rates).

- If a Trigger Event occurs in FY 2009, it may result in a Surcharge for FY 2009 if BPA is in a cash crunch in FY 2009. Such a Surcharge would be governed by the GRSPs published in the WP-07 Supplemental Final Proposal. If BPA is not in a cash crunch, or if a Surcharge implemented pursuant to the 2007 Supplemental GRSPs during FY 2009 collects less than the full amount of the FY 2009 Financial Effects, such a Trigger Event could lead to an NFB

Adjustment to the Cap on the CRAC applicable to FY 2010 and 2011, as governed by these GRSPs.

- If a Trigger Event occurs in FY 2010, it may result in either a Surcharge applicable to FY 2010 rates or an NFB Adjustment to the Cap on the CRAC applicable to FY 2011 rates. Such a Trigger Event may result in both NFB mechanisms being used if some but not all of the Financial Effects were recoverable from a Surcharge in FY 2010. All of these possibilities would be governed by these GRSPs.

- If a Trigger Event occurs in FY 2011 and BPA is in a cash crunch, the Surcharge procedures defined in these GRSPs will apply. If BPA is not in a cash crunch in FY 2011, these GRSPs are silent on the implications. Any NFB Adjustment that might apply to FY 2012 rates based on Trigger Events occurring in FY 2011 would be defined by subsequent GRSPs (*e.g.*, the 2012 GRSPs).

If a Trigger Event occurs that has Financial Effects in the year of its occurrence and also in later years, the Trigger Event will be deemed to have occurred on the first day of all subsequent years in which it has financial effects (*i.e.*, financial effects that have not been incorporated into the general rates applicable to that 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 of all Trigger Events combined.

5. NFB Adjustment and Surcharge Notification Processes

BPA shall use the following procedures following a Trigger Event:

(a) Notification of Trigger Event and Related Workshops

BPA will notify customers within 30 days of the occurrence of an NFB Trigger Event in FY 2010 or 2011, as defined above, if BPA estimates the Financial Effects of the Trigger Event to be $10 million or more. This initial notification, posted to BPA's Web site and provided by e-mail to those listed on the service list for the WP-10 rate proceeding, will include a description of the Trigger Event. If BPA estimates the Financial Effects of a Trigger Event to be less than $10 million, BPA may elect not to notify customers of the Trigger Event.

If BPA does not determine that the Agency Within-Year TPP is below 80 percent at any later time in the fiscal year, a Trigger Event with Financial Effects will result in an NFB Adjustment. The Financial Effects of the Trigger Event will be presented along with the forecast of the end-of-year AMNR calculation in September of that fiscal year. There can be more than one NFB Adjustment Trigger Event in a year. There will be only one, if any, calculation of the NFB Adjustment to the Cap on the CRAC applicable to the next year.

If the AMNR is forecast to fall below the Threshold for the CRAC applicable to the next year, BPA staff shall conduct a workshop(s), as called for by the CRAC procedures in Section II.D. 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. 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 Services Account Executives shall provide customers their Surcharge Percentages or REP benefit reduction.

On or about September 30, BPA will notify customers of the calculated final CRAC Percentage and REP benefit reductions. Any NFB Adjustment will be included in this final notification.

(b) Notification of Agency Within-Year TPP Falling Below 80 Percent Following a Trigger Event, and Related Workshops

If, during a fiscal year in which a Trigger Event has occurred, BPA determines 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 notification will be posted to BPA's Web site and provided by e-mail to those listed on the service list for the WP-10 rate proceeding.

This notification will include the time and location of a public workshop to be conducted no later than seven (7) days after the issuance of the notification. This notification will also include updated calculations of the Financial Effects of the Trigger Event(s) and the Agency Within-Year TPP. Concurrently, BPA's Power Services Account Executives will inform customers of their Surcharge Percentages or reduction to their benefits due to the Surcharge, as applicable.

At this workshop, BPA staff will explain the calculation of the Agency Within-Year TPP and the Surcharge Amount, including the monthly shape of payments.

BPA staff 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.

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

BPA will provide written Final Notification to each Customer in accordance with the notification provisions of the Customer's BPA contract no later than seven (7) days following the conclusion of the workshop described above. Such Final Notification will state the monthly Surcharge Amount or REP benefit reduction and the total Surcharge Amount or REP benefit reduction to be recovered from each customer by September 30 of the fiscal year that the Surcharge is in effect.

The monthly 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 Surcharge Amount will be billed no sooner than 30 days following the Final Notification.

2. **Process Following Implementation of Surcharge**

Within thirty (30) days of the Final Notification of implementation of a Surcharge described above, BPA will convene two or more meetings within 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 any other materials related to the Surcharge then in effect. BPA staff will provide responses to relevant information requests as promptly as possible, but in any case no later than 48 hours prior to the final meeting. Subsequent meetings may be held as necessary.

At the final 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, 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. The Administrator may remove the Surcharge entirely if one or both of the following occurs:

(a) the Agency Within-Year TPP, not including future surcharge payments, is determined at the time of the close-out letter to be greater than 90 percent.

(b) an updated calculation indicates that the Financial Effects of the Trigger Event(s) are less than $10 million for that fiscal year.

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.

The Excess Within-Day Factoring Charge, for any hour(s) in the month, applies to any 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)

(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.

The 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 greatest of:*

(1) 5 mills/kWh

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

(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 greatest of:*

(1) 5 mills/kWh

(2) The highest off-peak DJ Mid-C Index price for firm power during the month *less* the lowest off-peak DJ Mid-C Index price for firm power

(3) The highest average LLH CAISO Supplemental Energy price (NP15) (average of hours 1 through 6, 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 on-peak) and LLHs (or off-peak) 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 a Purchaser that makes a contractual commitment to purchase under this option. The rates 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 Purchaser under the Flexible NR rate option shall purchase the same set of power products and services that it would otherwise purchase under the rate schedule. The flexible rates and billing factors will be mutually agreed to by BPA and the Purchaser, subject to satisfying the following conditions:

Equivalent NPV Revenue: Forecast revenue from a Purchaser under the Flexible NR rate option must be equivalent, on a net present value basis, to the revenue BPA would have received had the appropriate rates specified in the NR rate schedule Section II been applied to the same sales.

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) rates 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 a Purchaser that makes a contractual commitment to purchase under this option. The rates 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 Purchaser under the Flexible PF rate option shall purchase the same set of power products and services that it would otherwise purchase under the rate schedule. The flexible rates and billing factors will be mutually agreed to by BPA and the Purchaser, subject to satisfying the following conditions:

Equivalent NPV Revenue: Forecast revenue from a Purchaser under the Flexible PF rate option must be equivalent, on a net present value basis, to the revenue BPA would have received had the appropriate rates 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) rates 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 shall 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 charge on a participating customer's power bill based on the amount of Environmentally Preferred Power (EPP), or its successor, or Alternative Renewable Energy (ARE) that the customer has elected to purchase. The GEP will be charged as a line item on the monthly power bill of each participating customer. The GEP will recover the forecast value of the environmental attributes associated with renewable resources included in the EPP and ARE portfolio.

During the FY 2010-2011 rate period, customers and BPA may agree to amend the Subscription contracts to convert the sale of EPP to the sale of Renewable Energy Certificates (RECs). In such event, the language herein that applies to EPP shall apply to RECs.

2. Calculation and Application of the Premium

(a) Determination of the Premium

BPA will set the GEP for the entire rate period, prior to the rate period. To derive the GEP, BPA will consider the forecast value of environmental attributes expected to be produced by resources included in the EPP and ARE portfolio, and any contractual call rights for EPP and ARE.

(b) Determination of Individual Customer GEP

Customers will be provided notice of the availability of EPP- and ARE-associated premiums. The total GEP for the customer will be based on the customer's purchase amount.

(c) Billing for the Premium

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

Bill$ = (EPP or ARE amount) kWh * GEP mills/kWh

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 rates for the following components of the PF Preference rate, the PF Exchange rate, and the New Resource rate: (1) Demand; (2) HLH Energy; (3) LLH Energy; 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 calendar year and shall become effective on the following October 1.

(a) The Kilowatthour/Investment Ratio

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

(b) The Consumers/Mile of Line Ratio

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

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

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 below, 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 calendar year 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 Purchaser's 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 data needed to calculate the K/I and C/M ratios by June 30 of each year, for the prior calendar year, shall be declared ineligible for the LDD, effective the following October 1.

If a Purchaser's data was timely submitted, and a revision is necessary to the data, the revised data must be submitted 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 to retail consumers.

(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.

(e) The Purchaser’s C/M ratio must be less than 12.

3. Discounts

The Purchaser shall be awarded the following discount beginning October 1, 2009, 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 D. The total discount shall not exceed 7 percent.

Table D
LDD Percentage Discount Table

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

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 one of the following amounts:

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

(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 existing discount is fully phased to the calculated discount.

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.

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 II.L.3 and 4, 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 pursuant to section II.L.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.

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 II.L.2.

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

> By September of each year, BPA will establish a mills/kWh LDD discount rate for each one-half percent discount bracket, from 0.5 percent to 7 percent. The mills per kWh discount rate for each bracket will be determined by using billing data of customers within the same non-Slice LDD percentage bracket. Non-Slice total dollar LDD discounts will be divided by the total LDD-eligible energy purchased. The resulting mills/kWh rate can then be used as the yearly/monthly discount for a Slice

customer that is eligible, pursuant to section II.L.3, to receive the same discount. BPA will use billing data from the previous calendar year from the non-Slice LDD recipients when calculating the mills/kWh discount rate for Slice product recipients. When there are no non-Slice LDD recipients available in a given discount bracket to calculate the mills/kWh value, it is appropriate to determine a linear relationship using a regression analysis to arrive at a mills/kWh 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 mills/kWh rate that coincides with the increase or decrease in rate(s) for the non-Slice LDD recipients for the same period.

The LDD discount rate will be applied to only 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 BPA used to establish the melded rates and provide 30 days for the customer to review and accept the melding calculation before BPA 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 occurs in the loads applicable to the rates.

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 for such fiscal year and the average Slice Revenue Requirement upon which the applicable Slice rate is based. The Actual Slice Revenue Requirement for the applicable fiscal year is the sum of the final audited expenditures and revenues as reflected on BPA's financial statements, corresponding to those Power Services 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 2010, BPA will calculate the difference between the Actual Slice Revenue Requirement for FY 2010 and the average Slice Revenue Requirement for FY 2010-2011 determined in the WP-10 rate proceeding (*see* Slice Rate Methodology, Appendix A, Table 1, Slice Product Costing and True-Up Table).

The difference between the Actual Slice Revenue Requirement and the average 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 fiscal year exceeds the average Slice Revenue Requirement determined in the WP-10 rate proceeding, 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 fiscal year is less than the average Slice Revenue Requirement determined in the WP-10 rate proceeding, 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 average Slice Revenue Requirement determined in the WP-10 rate proceeding, 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. The resulting amounts will be included on the Slice customer bills as the Slice True-Up Adjustment Charges or Credits.

2. Slice Implementation Expenses

In addition, following the end of each fiscal year, BPA will calculate the amount of Slice Implementation Expenses incurred during that fiscal year. Slice customers will be charged for 100 percent of these expenses, and these expenses will be allocated on the basis of each Slice customer's Selected Slice Percentage, relative to the total of Slice all customers' Selected Slice Percentages. For example, if a 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). The resulting amounts will be included on the Slice customer bills as Slice True-Up Implementation Expense charges at the same time as the Slice True-Up Adjustment Charges or Credits.

3. Individual Charges and Individual Credits

For a Slice customer that purchases additional services from BPA, or that elects certain contractual options, BPA will calculate the amount of Individual Charge that will be added to its bill at the same time as the Slice True-Up Adjustment

Charge. For a customer that elects certain contractual options, BPA will calculate the amount of Individual Credit that will be factored into its bill at the same time as the Slice True-Up Adjustment Charge.

O. 7(b)(3) Supplemental Rate Charge Adjustment

1. ASC Adjustment

The 7(b)(3) Supplemental Rate Charge is a utility-specific addition to the Base PF Exchange rate that recovers each REP participant's allocated share of the rate protection provided pursuant to section 7(b)(2) of the Northwest Power Act. Each REP participant's initial 7(b)(3) Supplemental Rate Charge is determined in a section 7(i) rate proceeding based on the Base PF Exchange rate and the Average System Cost (ASC) and forecast exchange loads of all utilities assumed in ratemaking to participate in the Residential Exchange Program. Each REP participant's initial 7(b)(3) Supplemental Rate Charge is displayed in the table in Section III.A.1.3 of the PF-10 rate schedule, and is subject to modification under this GRSP.

Under the 2008 Average System Cost Methodology, when a participating utility files an ASC with BPA, the utility may request an ASC modification based on the expectation that its set of resources will change during BPA's rate period. The participating utility must file the expected changes to its ASC with its ASC filing. Subject to limitations in the 2008 ASC Methodology, BPA will establish a modified ASC for a utility during BPA's rate period effective with the operational date of the new resource. Therefore, if a participating utility's ASC differs from the ASC set forth in Table E below, BPA will adjust the 7(b)(3) Supplemental Rate Charges of all participating utilities to reflect the new ASC.

Such adjustment of 7(b)(3) Supplemental Rate Charges will be accomplished by substituting all modified ASCs in column A of Table E, and recomputing column E:

Table E: Adjustment of 7(b)(3) Supplemental Rate Charges

		A	B	C	D	E
1		**Applicable ASC**	**Rate Period Forecast Load**	**Surcharge Allocator ($000)**	**Reallocation ($000)**	**7(b)(3) Supplemental Rate Charge**
2	Avista	44.61	8,020	$32,294	$15,837	1.97
3	Idaho Power	35.65	13,188	$0	$0	0
4	Northwestern Energy	57.57	1,248	$21,197	$10,395	8.33
5	PacifiCorp	54.80	19,170	$272,575	$133,673	6.97
6	Portland General	55.57	17,588	$263,580	$129,261	7.35
7	Puget Sound Energy	57.03	23,972	$394,339	$193,386	8.07
8	Franklin	49.28	714	$6,213	$3,047	4.26
9	Snohomish	47.67	7,578	$53,706	$26,338	3.48
10	Total		91,477	$1,043,904	$511,938	

Where:

- Column A is the participating utility's Average System Cost for the month, expressed in mills/kWh (equivalent to $/MWh). The values displayed in this column are for the start of FY 2010 (October 1, 2009), and do not include any new resource additions that are expected to come online during the exchange period.
- Column B is the combined forecast total 2-year exchange load for the participating utility, expressed in gigawatthours, as adopted in the WP-10 rate proceeding.
- Column C is the result of multiplying Column B times the difference between Column A and the Base PF Exchange rate (40.58 mills/kWh).
- Total of Column C is the sum of the values in Column C.
- Total of Column D is the difference between the Total of Column C and $531,966,000 (the total REP benefits adopted for the 2-year rate period in the WP-10 rate proceeding). This difference is subject to change by application of the Cost Recovery Adjustment Clause and/or the Dividend Distribution Clause. See Sections II.D.1.e and II.F.1.d.
- Column D is the Total of Column D reallocated *pro rata* using Column C allocators.
- Column E is the new utility-specific 7(b)(3) Supplemental Rate Charge, expressed in mills/kWh, computed by dividing Column D by Column B.

The adjusted 7(b)(3) Supplemental Rate Charges will take effect on the day that the utility's modified ASC takes effect. This adjustment will occur as frequently as ASCs are modified during the 2-year rate period the PF Exchange rate herein is in effect.

Table E above, Adjustment of 7(b)(3) Supplemental Rate Charges, will be published monthly and updated as ASCs are modified. The table can be accessed through the Residential Exchange Program Web site at http://www.bpa.gov/corporate/finance/ascm/

2. Change in Service Territory due to Annexation or Load Transfer

Should an REP-participating utility lose or gain load through an annexation or other transfer of load, the total REP benefits of $531,966,000 used in the 7(b)(3) Supplemental Rate Charge calculation in section O.1 will be subject to change. If load is transferred from a participating utility to a preference customer, resulting in an increase in PF preference load on BPA, and thereby increasing BPA's expenses, then the reduction in REP benefits to the REP-participating IOU will reduce the $531,966,000 by the same amount. If the load is transferred from a participating utility to another utility such that BPA expenses are not increased due to the transferred load, then the $531,966,000 will not be reduced. The $531,966,000 cannot be increased through a transfer of load.

P. Targeted Adjustment Charge (TAC)

1. Availability

The TAC applies to purchases under 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, 2008. TAC also applies to customers that add load through retail access, including load that was once served and returns under retail access.

The 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-10 or NR-10 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.

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 Residential Purchase and Sale Agreement (RPSA) as amended, the IOU will realize a reduction in the amount of its RPSA benefit payment. BPA will account for such reduced RPSA benefits as an offset against the TAC charged to the public agency customer. The public agency customer will be responsible for any TAC in excess of the amount of the offset.

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 (one) 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 agency customer requests service, the TAC, if any, will apply until September 30, 2011.

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 2010-2011 rate period, requirements firm power service for such load at the end of the specified contract period at the PF Preference 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 2010 rate schedules, 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 for each diurnal period.
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, as established in the WP-10 rate proceeding, 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 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 greatest 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 the CAISO Expanded region.

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 capacity prices for all HLHs in the month, at a hub at which Northwest parties can trade, established between October 1, 2009, and September 30, 2011.

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

(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

(2) The highest hourly CAISO Imbalance Energy price (Malin).

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

In the event that either the CAISO Imbalance 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 the highest price 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, 2009, and September 30, 2011.

R. West-wide Price Cap of FPS Sales

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

S. DSI Reserves Adjustment

A DSI customer's IP bill may be adjusted to reflect a DSI Reserves Adjustment. BPA Power Services is not obligated to purchase any DSI Reserve(s) beyond the Minimum DSI Operating Reserve – Supplemental, but is willing to negotiate with any DSI interested in providing DSI Reserves. A DSI Reserve is provided through the ability to interrupt, curtail, or otherwise reduce DSI load when such a right is made available to Power Services in addition to the Minimum DSI Operating Reserve – Supplemental.

This optional DSI Reserves Adjustment is designed to provide the flexibility that will allow BPA to negotiate company-specific interruption rights, with the rate based on the characteristics of the DSI Reserve(s) provided. To ensure that any such purchases by BPA are cost effective, the maximum amount Power Services may pay a DSI for DSI Reserve(s) is $6.02 per kW per month.

The availability of DSI Reserve(s) purchased by Power Services must be consistent with North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), or Northwest Power Pool (NWPP) standards and criteria:

1. The interruptible load must be offline or the increased generation must be online within the period specified for the applicable DSI Reserve purchased; and

2. The interruptible load or increased generation must be accessible prior to a request for reserves from other NWPP parties.

In addition to these two required characteristics, the issues identified below will help define when Power Services may pay the maximum value for DSI Reserves:

1. The extent to which Power Services has the discretion when and how to use all reserves and to determine what resources to call on in the event of a system disturbance, or for some other purpose specified in the negotiated arrangement;

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

3. Duration of time the interruptible load is available to be offline or increased generation is available to be online.

Even in the event that a DSI is willing to provide reserves meeting all of the criteria established above, the Administrator is not obligated to purchase such optional reserves.

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SECTION III. DEFINITIONS

A. Power Products and Services Offered By BPA Power Services

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.

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's 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 of the Capacity product. 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-10), New Resources Firm Power (NR-10), and Firm Power Products and Services (FPS-10) rate schedules. Such power is not available under the PF Exchange rate.

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

(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. 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.

9. Industrial Firm Power (IP)

Industrial Firm Power (IP) is electric power that BPA will make available to a DSI Purchaser subject to the terms of the Purchaser's power sales contract with BPA.

10. Load Variance

For Core Subscription products, Load Variance is defined as the variability in hour-to-hour or month-to-month 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.

11. 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, as defined in the Northwest Power Act

(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 for which BPA's Transmission Services may agree to provide operating reserves in accordance with the standards established by NERC, WECC, and NWPP.

12. 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 Program (REP) may purchase PF pursuant to their RPSA 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.

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 for which BPA's Transmission Services may agree to provide operating reserves in accordance with the standards established by NERC, WECC, and NWPP.

13. 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.

14. Residential Exchange Program Power

Residential Exchange Program Power is power BPA sells to a Purchaser pursuant to the REP. Under Section 5(c) of the Northwest Power Act, BPA "purchases" power from eligible 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 (PF Exchange rate). The amount of power purchased and sold are both 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.

15. Slice Product

The Slice product is a power sale based upon an eligible customer's annual firm net requirement load and is shaped to BPA's generation from the FCRPS through 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 purchasers' percentage entitlements are set by contract. The Slice product includes both service to net requirements firm load and an advance sale of surplus power.

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. Balancing Authority Area

A balancing authority area (formerly known as 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 balancing authority areas.

3. 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.

4. 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.

5. California Independent System Operator (CAISO)

The FERC-regulated balancing authority 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.

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

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

7. California Independent System Operator (CAISO) Imbalance Energy

Energy from generating units and other resources which have uncommitted capacity following finalization and posting of the Day-Ahead schedules and for which scheduling coordinators have submitted bids to the CAISO at least 75 minutes before the commencement of the settlement period.

8. 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.

9. Contract Energy

Contract Energy is the maximum number of kilowatthours 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.

10. Customer System Peak (CSP)

Customer System Peak is the largest measured HLH Total Retail Load amount, in kilowatts, for the billing period.

11. Delivering Party

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

12. 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.

13. Discount Period

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

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

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

15. DSI Reserve

A DSI Reserve is any interruption right in addition to the Minimum DSI Operating Reserve – Supplemental, consistent with the DSI Reserves Adjustment standards and criteria described in Section II.S of the GRSPs, that is provided by a DSI to Power Services in a contract with BPA.

16. Electric Power

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

17. Energy Entitlement

For purchases made under contracts for Core Subscription products:

(a) HLH Energy Entitlement is the sum, in kWh, of amounts of HLH energy that the Purchaser is entitled to receive from BPA, as specified in the contract.

(b) LLH Energy Entitlement is the sum, in kWh, of amounts of LLH energy that the Purchaser is entitled to receive from BPA, as specified in the contract.

18. 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.

19. Firm Power (PF-10, IP-10, NR-10)

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.

20. Full Service Customer

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

21. Generation System Peak (GSP)

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

22. Heavy Load Hours (HLH)

Heavy Load Hours (HLH) are all hours in the on-peak period – the 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 recognizes NERC Standards in classifying six holidays as Light Load Hours.

23. Inventory Solution (or Augmentation)

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

24. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the off-peak period – the 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 recognizes six holidays classified according to NERC Standards as LLH. Memorial Day, Labor Day, and Thanksgiving Day 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 the predetermined dates fall on a Sunday, the holiday is recognized as the Monday immediately following that Sunday, so that Monday is also LLH all day. If the predetermined dates fall on a Saturday, the holiday is recognized as that Saturday, and that Saturday is classified as LLH.

25. 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.

26. 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.

27. 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.

28. Metered Energy

The Metered Energy for a purchaser shall be the amount of kilowatthours 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.

29. Minimum DSI Operating Reserve – Supplemental

The Minimum DSI Operating Reserve – Supplemental is a right to interrupt DSI load made available by each DSI purchasing Industrial Firm Power in a megawatt amount equal to 10 percent of Net Industrial Firm Power. The availability of the Minimum DSI Operating Reserve – Supplemental must be consistent with North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), or Northwest Power Pool (NWPP) standards and criteria:

a. The interruptible load must be offline or the increased generation must be online within 10 minutes after a call from BPA;

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

c. The interruptible load must be available to be offline for up to 105 minutes, or increased generation must be available to be online for up to 105 minutes.

d. There are no limitations on the number of times or aggregate minutes the Minimum DSI Operating Reserve – Supplemental may be utilized.

The energy charges stated in the IP-10 Rate Schedule reflect the credit for the value of the Minimum DSI Operating Reserve – Supplemental.

30. 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 balancing authority area and scheduled imports for BPA’s account from other balancing authority areas.

31. Net Billing Capacity Deficiency

A Net Billing Capacity Deficiency means that, 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.

32. Net Industrial Firm Power

For purposes of the definition of Minimum DSI Operating Reserve – Supplemental, Net Industrial Firm Power shall equal the Industrial Firm Power less the sum of: (a) any power restricted by BPA under any other agreement, and (b) Wheel Turning Load.

33. NP15

The portion of the CAISO balancing authority area north of transmission path 15.

34. NW1 (COB)

CAISO designation for delivery at COB (including Captain Jack/Malin).

35. NW3 (NOB)

CAISO designation for delivery at NOB.

36. Partial Service Customer

A Partial Service customer is any customer that is not a Full Service customer.

37. 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 may be located at the change of ownership point on a transmission line.

38. 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 may be located at some other interconnection point to receive system power from the customer.

39. Point of Interconnection (POI)

A Point of Interconnection is a point where the facilities of two entities are interconnected.

40. Points of Metering (POM)

The POM shall be those points specified in the contract at which Total Retail Load and Metered Amounts are measured.

41. 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. A small number of these contracts extend through 2011.

42. Purchaser

Pursuant to the terms of an agreement and applicable rate schedule(s), a Purchaser is the entity that contracts to pay BPA for providing a product or service.

43. Receiving Party

The entity receiving the capacity and/or energy transmitted by BPA to a Point(s) of Delivery.

44. 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.

45. Scheduled Demand

For purposes of applying the rates herein to applicable purchases by the Purchaser, the Scheduled Demand, in kilowatts, 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.

46. Scheduled Energy

For purposes of applying the rates herein to applicable purchases by the Purchaser, Scheduled Energy, in kilowatthours, 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.

47. Slice Revenue Requirement

The Slice Revenue Requirement is comprised of items in BPA's Power Services revenue requirement, and is the basis for the Slice rate, as identified in the Power Services WP-02, WP-07, WP-07 Supplemental, and WP-10 rate cases. *See* Appendix A, Table 1, Slice Product Costing and True-Up Table.

48. Subscription

Subscription refers to the Power Subscription Strategy issued by BPA on December 21, 1998, which is BPA's policy for power sales for FY 2002-2011.

49. Subscription Contract

Such power sales contract effective during the period between October 1, 2001, and September 30, 2011.

50. 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.

51. 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.

52. Wheel Turning Load

Wheel Turning Load is that portion of Total Plant Load which is not integral to a Purchaser's industrial process and is not a part of a technological allowance. A megawatt amount of Wheel Turning Load shall be defined in the Purchaser's power sales contract with BPA, unless such amount is self-supplied. Wheel Turning Load shall be exempt from reduction or interruption associated with providing Minimum DSI Operating Reserve – Supplemental.

Appendix A
FY 2002-2011 Slice Rate Methodology

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APPENDIX A

FY 2002-2011 SLICE RATE METHODOLOGY

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.

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.

Forecast Loads for each rate period shall be the average of the forecast 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.

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.

For the FY 2010-2011 rate period, the Slice Revenue Requirement will contain the costs and credits estimated in the WP-10 rate proceeding 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 two-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

Power Services costs or credits not otherwise specifically dealt with in the Slice Revenue Requirement, or excluded therefrom 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 Power Services costs or credits could be properly includable in Power Services' wholesale power rates; and either

a. Such Power Services costs or credits are: (1) incurred by Power Services to provide service to customers other than Slice purchasers; and (2) incurred to provide service to or otherwise benefit Slice purchasers;

OR

b. Such Power Services 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.

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 forecast 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 Power Services 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 Power Services' 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).

b. Transmission Surcharge

As provided for under separate rate and contract, BPA's Transmission Services may impose a transmission surcharge on the Slice purchaser's use of the BPA transmission system. Any revenues received by Transmission Services pursuant to such surcharge will be credited to Power Services' total Actual Slice Revenue Requirement, and will be reflected in the Slice purchaser's True-Up Adjustment. Repayment of such funds by the Power Services to Transmission Services, 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 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 2010 GRSPs or any successor thereto.

7. Net Cost of the Inventory Solution

BPA has forecast firm energy purchases that supplement the capability of FBS Resources (Inventory Solution) to meet the forecast 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 forecast 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 forecast net cost of the Inventory Solution to be included in the Slice Revenue Requirement for the FY 2010-2011 rate period is identified in Table 1.

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 average Slice Revenue Requirement for the applicable rate period 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 2010 forecast	FY 2011 forecast
1	**Operating Expenses**			
2	**Power System Generation Resources**			
3	**Operating Generation**			
4	COLUMBIA GENERATING STATION (WNP-2)		$ 257,811	$ 324,882
5	BUREAU OF RECLAMATION		$ 87,318	$ 96,110
6	CORPS OF ENGINEERS		$ 191,060	$ 192,433
7	LONG-TERM CONTRACT GENERATING PROJECTS		$ 30,455	$ 30,767
8	**Sub-Total**		**$ 566,644**	**$ 644,192**
9	**Operating Generation Settlement Payment**			
10	COLVILLE GENERATION SETTLEMENT		$ 21,328	$ 21,754
11	**Sub-Total**		**$ 21,328**	**$ 21,754**
12	**Non-Operating Generation**			
13	TROJAN DECOMMISSIONING		$ 2,200	$ 2,300
14	WNP-1&3 DECOMMISSIONING		$ 418	$ 428
15	**Sub-Total**		**$ 2,618**	**$ 2,728**
16	**Contracted Power Purchases**			
17	HEDGING/MITIGATION (omit except for those assoc. with inventory solution)		$ -	$ -
18	PNCA HEADWATER BENEFITS		$ 2,042	$ 2,620
19	GROSS OTHER POWER PURCHASES (short term - omit)			
20	**Sub-Total**		**$ 2,042**	**$ 2,620**
21	**Bookout Adjustment to Power Purchases (omit)**			
22	**Augmentation Power Purchases (omit - calculated below)**			
23	AUGMENTATION POWER PURCHASES (omit)			
24	CONSERVATION AUGMENTATION (omit)			
25	**Sub-Total**		**$ -**	**$ -**
26	**Exchanges and Settlements**			
27	PUBLIC RESIDENTIAL EXCHANGE		$ 12,101	$ 10,016
28	IOU RESIDENTIAL EXCHANGE		$ 254,770	$ 258,667
29	OTHER SETTLEMENTS		$ -	$ -
30	**Sub-Total**		**$ 266,871**	**$ 268,683**
31	**Renewable Generation**			
32	RENEWABLES R&D		$ 6,174	$ 6,133
33	RENEWABLES CONSERVATION RATE CREDIT		$ 4,000	$ 2,500
34	RENEWABLES (excludes expenses from reinvested revenues)		$ 30,374	$ 30,965
35	**Sub-Total**		**$ 40,548**	**$ 39,598**
36	**Generation Conservation**			
37	GENERATION CONSERVATION R&D			
38	DSM TECHNOLOGIES		$ -	$ -
39	CONSERVATION ACQUISITION		$ 14,000	$ 14,000
40	LOW INCOME WEATHERIZATION & TRIBAL		$ 5,000	$ 5,000
41	ENERGY EFFICIENCY DEVELOPMENT		$ 20,500	$ 20,500
42	LEGACY		$ 1,988	$ 1,622
43	MARKET TRANSFORMATION		$ 14,500	$ 14,500
44	**Sub-Total**		**$ 55,988**	**$ 55,622**
45	**Conservation and Renewable Discount (C&RD)**			
46	CONSERVATION RATE CREDIT		$ 28,000	$ 29,500
47	CONSERVATION AND RENEWABLE DISCOUNT			
48	**Sub-Total**		**$ 28,000**	**$ 29,500**
49	**Power System Generation Sub-Total**		**$ 984,039**	**$ 1,064,697**
50	**Power Services Transmission Acquisition and Ancillary Services**			
51	**Transmission Acquisition and Ancillary Services**			
52	TRANSMISSION & ANCILLARY SERVICES			
53	Canadian Entitlement Agreement Transmission Expenses		$ 27,000	$ 27,000
54	PNCA & NTS Transmission and System Obligaton Expenses		$ 1,000	$ 1,000
55	3RD PARTY GTA WHEELING		$ 50,690	$ 51,340
56	3RD PARTY TRANS & ANCILLARY SVCS			
57	GENERATION INTEGRATION		$ 6,800	$ 6,800
58	TELEMETERING/EQUIP REPLACEMT		$ 50	$ 50
59	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**		**$ 85,540**	**$ 86,190**

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

	($000s)	Audited Actual Data	FY 2010 forecast	FY 2011 forecast
60				
61	**Power Non-Generation Operations**			
62	**System Operations**			
63	SYSTEM OPERATIONS R&D		$ -	$ -
64	EFFICIENCIES PROGRAM (excludes TMS expenses)		$ -	$ -
65	INFORMATION TECHNOLOGY		$ 6,318	$ 6,282
66	GENERATION PROJECT COORDINATION		$ 7,290	$ 7,542
67	SLICE IMPLEMENTATION (omit - calculated separately)			
68	**Sub-Total**		**$ 13,608**	**$ 13,824**
69	**Scheduling**			
70	SCHEDULING R&D			
71	OPERATIONS SCHEDULING		$ 9,317	$ 9,564
72	OPERATIONS PLANNING		$ 5,808	$ 5,874
73	**Sub-Total**		**$ 15,125**	**$ 15,438**
74	**Marketing and Business Support**			
75	SALES & SUPPORT		$ 16,699	$ 17,885
76	Contractual exclusion		$ (5,360)	$ (5,360)
77	Implementation Expense Exclusions - Add back			
78	PUBLIC COMMUNICATION & TRIBAL LIAISON			
79	STRATEGY, FINANCE & RISK MGMT		$ 16,870	$ 17,343
80	EXECUTIVE AND ADMINISTRATIVE SERVICES		$ 2,546	$ 2,727
81	CONSERVATION SUPPORT (EE staff costs)		$ 11,356	$ 12,003
82	**Sub-Total**		**$ 42,111**	**$ 44,598**
83	**Power Non-Generation Operations Sub-Total**		**$ 70,844**	**$ 73,860**
84	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
85	**BPA Fish and Wildlife (includes F&W Shared Services)**			
86	FISH & WILDLIFE		$ 215,000	$ 236,000
87	**Sub-Total**		**$ 215,000**	**$ 236,000**
88	**USF&W Lower Snake Hatcheries**			
89	USF&W LOWER SNAKE HATCHERIES		$ 23,600	$ 24,480
90	**Planning Council**			
91	PLANNING COUNCIL		$ 9,683	$ 9,934
92	**Environmental Requirements**			
93	ENVIRONMENTAL REQUIREMENTS		$ 300	$ 300
94	**Fish and Wildlife/USF&W/Planning Council Sub-Total**		**$ 248,583**	**$ 270,714**
95	**General and Administrative/Shared Services**			
96	**Additional Post-Retirement Contribution**			
97	ADDITIONAL POST-RETIREMENT CONTRIBUTION		$ 15,447	$ 15,579
98	**BPA Internal Support - G&A and Shared Srv. (excludes direct project support)**			
99	AGENCY SERVICES G&A		$ 49,961	$ 50,064
100	**Sub-Total BPA Internal Support Services**		**$ 49,961**	**$ 50,064**
101	**Supply Chain - Shared Services**			
102	**General and Administrative/Shared Services Sub-Total**		**$ 65,408**	**$ 65,643**
103	**Bad Debt Expense**		$ -	$ -
104	**Other Income, Expenses, Adjustments**		**$ -**	**$ -**
105	**Non-Federal Debt Service**			
106	**Energy Northwest Debt Service**			
107	COLUMBIA GENERATING STATION DEBT SVC		$ 235,736	$ 226,169
108	WNP-1 DEBT SVC		$ 166,013	$ 167,549
109	WNP-3 DEBT SVC		$ 144,892	$ 169,093
110	EN RETIRED DEBT			
111	EN LIBOR INTEREST RATE SWAP			
112	**Sub-Total**		**$ 546,641**	**$ 562,811**
113	**Non-EN Debt Service**			
114	COWLITZ FALLS DEBT SVC		$ 11,566	$ 11,563
115	N. WASCO DEBT SVC		$ 2,200	$ 2,196
116	TROJAN DEBT SVC		$ -	$ -
117	CONSERVATION DEBT SVC		$ 5,079	$ 4,924
118	**Sub-Total**		**$ 18,845**	**$ 18,683**
119	**Non-Federal Debt Service Sub-Total**		**$ 565,486**	**$ 581,494**
120	**Depreciation (excludes TMS)**		$ 120,111	$ 121,235
121	**Amortization (excludes ConAug amortization)**		$ 64,392	$ 72,363
122	**Total Operating Expenses**		**$ 2,204,403**	**$ 2,336,196**

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

($000s)

		Audited Actual Data	FY 2010 forecast	FY 2011 forecast	
123					
124	**Other Expenses**				
125	Net Interest Expense		$ 167,119	$ 173,301	
126	LDD		$ 26,419	$ 26,465	
127	Irrigation Rate Mitigation Costs		$ 12,036	$ 12,036	
128	**Sub-Total**		**$ 205,574**	**$ 211,802**	
129	**Total Expenses**		**$ 2,409,977**	**$ 2,547,998**	
130					
131	**Revenue Credits**				
132	Ancillary and Reserve Service Revs. Total		$ 90,176	$ 102,730	
133	Downstream Benefits and Pumping Power		$ 8,921	$ 8,921	
134	4(h)(10)(c)		$ 96,689	$ 101,969	
135	Colville and Spokane Settlements		$ 4,600	$ 4,600	
136	FCCF				
137	Energy Efficiency Revenues		$ 20,500	$ 20,500	
138	Miscellaneous		$ 3,420	$ 3,420	
139	Green Tag revenue associated with Klondike III		$ -	$ -	
140	Ad Hoc revenue credit adjustment				
141	**Total Revenue Credits**		**$ 224,306**	**$ 242,140**	
142	**Augmentation Costs (not subject to True-Up)**				
143	**Non-DSI Net Augmentation Costs**				
144	Gross Augmentation cost (72.7 aMW, 274.7 aMW)		$ 26,019	$ 108,375	
145	Minus revenues 70.7 aMW, 267.1 aMW @ PF rate		$ (17,815)	$ (67,325)	
146			**$ 8,204**	**$ 41,050**	
147	**DSI Net Augmentation Costs**				
148	Gross Augmentation cost (413 aMW, 413 aMW)		$ 154,746	$ 164,668	
149	Minus revenues 402 aMW, 402 aMW @ IP rate		$ (121,852)	$ (121,852)	
150			**$ 32,895**	**$ 42,815**	
151					
152	**Total Net Cost of Augmentation**		**$ 41,099**	**$ 83,865**	
153					
154					
155	**Minimum Required Net Revenue calculation**				
156	Principal Payment of Fed Debt for Power		$ 202,673	$ 204,163	
157	Irrigation assistance		$ -	$ -	
158	Depreciation		$ 120,111	$ 121,235	
159	Amortization		$ 77,728	$ 85,699	
160	Capitalization Adjustment		$ (45,937)	$ (45,937)	
161	Bond Premium Amortization		$ 185	$ 185	
162	Principal Payment of Fed Debt exceeds non cash expenses		$ 50,586	$ 42,981	
163	Minimum Required Net Revenues		**$ 50,586**	**$ 42,981**	
164					**2-Year Total Rev**
165	Annual Slice Revenue Requirement (Amounts for each FY)		**$ 2,277,356**	**$ 2,432,704**	**$ 4,710,060**
166					
167	SLICE TRUE-UP ADJUSTMENT CALCULATION				
168					
169	FY 2010-2011 Average Slice Revenue Requirement determined in WP-10 rate case		**$ 2,355,030**		
170	TRUE UP AMOUNT (Diff. between actual Slice Rev Reqt and forecast average Slice Rev Reqt)				
171	AMOUNT BILLED (22.6278 percent)				
172	Slice Implementation Expenses (not incl. in base rate)				
173	TRUE UP ADJUSTMENT				
174					
175					
176	**SLICE RATE CALCULATION ($)**				
177	**Monthly Slice Revenue Requirement (2-Year total divided by 24 months)**				**$ 196,252,520**
178	**One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Rev. Req't. divided by 100)**				**$ 1,962,525**
179					
180	**ANNUAL BASE SLICE REVENUES**				**$ 532,891,534**
181	**Annual Slice Implementation Expenses**				**$ 2,830,000**
182	**TOTAL ANNUAL SLICE REVENUES**				**$ 535,721,534**

Appendix B

Customer Lookback Credit in FY 2010-2011

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Customer Lookback Credit in FY 2010-2011

Section 1. Purpose

The Customer Lookback Credit in FY 2010-2011 is a credit on a customer's power bill that reflects the return of a portion of overcharges for the Residential Exchange Program (REP) settlement agreements incurred by customers who paid the PF-02 rate in FY 2002-2006. The amount of the credit is determined in each rate case until the total Lookback Amount is extinguished. The Total FY 2010-2011 Lookback Credit Amount is determined in the WP-10 rate proceeding.

Section 2. Terms of the Customer Lookback Credit

The Customer Lookback Credit applies to customers that purchased power from BPA at the PF-02 Priority Firm rates under their Subscription contracts.

Credits shall appear on monthly power bills beginning with the month that the rates established in the WP-10 rate proceeding take effect. The FY 2010-2011 credit will be provided in 24 equal monthly amounts that total to the 2-year total for FY 2010-2011.

Section 3. Definitions

<u>Total FY 2010-2011 Lookback Credit Amount</u> is the portion of the REP settlement agreement overcharges incurred by customers who paid the PF-02 rates that will be returned to Slice and Non-Slice customers in FY 2010-2011.

<u>Non-Slice FY 2010-2011 Lookback Credit Amount</u> is the portion of the Total FY 2010-2011 Lookback Credit Amount that is due to customers that paid the PF-02 non-Slice rates. It is equal to 77.3722 percent of the Total FY 2010-2011 Lookback Credit Amount.

<u>Non-Slice PF-02 Revenue Share</u> is the percentage used to allocate the Non-Slice FY 2010-2011 Lookback Credit Amount to each customer that paid the non-Slice PF-02 rates. It is equal to the ratio of each customer's non-Slice PF-02 revenues, including revenues from block purchases of the Slice customers, divided by the total non-Slice revenues at the PF-02 rate collected from all non-Slice customers, including revenues from block purchases.

<u>Non-Slice Monthly FY 2010-2011 Lookback Credit Amount</u> is the monthly credit due to each non-Slice customer in FY 2010-2011 that paid the non-Slice PF-02 rates. It is equal to the Non-Slice FY 2010-2011 Lookback Credit Amount times the Non-Slice PF-02 Revenue Share divided by 24.

<u>Slice FY 2010-2011 Lookback Credit Amount</u> is the portion of the Total FY 2010-2011 Lookback Credit Amount that is due to customers that paid the PF-02 Slice rate. It is equal to 22.6278 percent of the Total FY 2010-2011 Lookback Credit Amount.

Slice % Share is the percentage used to allocate the Slice FY 2010-2011 Lookback Credit Amount to each Slice customer. It is equal to each Slice customer's Slice percentage divided by the sum of all customers' Slice percentages (22.6278 percent).

Slice Monthly FY2010-2011 Lookback Credit Amount is the monthly credit due to each Slice customer in FY 2010-2011 that paid the Slice PF-02 rate. It is equal to the Slice FY 2010-2011 Lookback Credit Amount times the Slice % Share divided by 24.

Section 4. Customer Lookback Credit Amounts

As displayed on the following table:

Customer Lookback Credit Amounts

This sheet calculates Slice credits for PNGC members only on their retained slice percentages the bulk is refunded to PNGC

Total FY 2010-2011 Lookback Credit Amount	**$**	**163,144,416**
Slice FY 2010-2011 Lookback Credit Amount	$	36,915,992
Non-Slice FY 2010-2011 Lookback Credit Amount	$	126,228,424

	Customer Name	**Corrected Non-Slice PF-02 Revenue Share**	**Non-Slice Monthly FY10-11 Lookback Credit Amount**	**Slice % Share**	**Slice Monthly FY10-11 Lookback Credit Amount**
10055	Albion, City of	0.0000%	$ -	0.0000%	$ -
10005	Alder Mutual	0.0107%	$ 565	0.0000%	$ -
10057	Ashland, City of	0.5455%	$ 28,690	0.0000%	$ -
10015	Asotin County PUD #1	0.0000%	$ -	0.0000%	$ -
10059	Bandon, City of	0.1876%	$ 9,868	0.0000%	$ -
10024	Benton County PUD #1	1.3492%	$ 70,964	7.7962%	$ 119,918
10025	Benton REA	1.2358%	$ 64,997	0.0000%	$ -
10027	Big Bend Elec Coop	0.6098%	$ 32,072	0.0000%	$ -
10028	Big Horn County Electric Coop.	0.0000%	$ -	0.0000%	$ -
10029	Blachly Lane Elec Coop	0.0000%	$ -	0.2907%	$ 4,471
10061	Blaine, City of	0.2043%	$ 10,748	0.0000%	$ -
10062	Bonners Ferry, City of	0.1540%	$ 8,098	0.0000%	$ -
10064	Burley, City of	0.3559%	$ 18,720	0.0000%	$ -
10044	Canby, City of	0.4958%	$ 26,075	0.0000%	$ -
10065	Cascade Locks, City of	0.0605%	$ 3,182	0.0000%	$ -
10046	Central Electric Coop	0.0000%	$ -	1.0149%	$ 15,611
10047	Central Lincoln PUD	1.6322%	$ 85,845	0.0000%	$ -
10048	Central Montana Electric Power Coop	0.0000%	$ -	0.0000%	$ -
10066	Centralia, City of	0.5547%	$ 29,172	0.0000%	$ -
10067	Cheney, City of	0.3668%	$ 19,292	0.0000%	$ -
10068	Chewelah, City of	0.0000%	$ -	0.0000%	$ -
10101	Clallam County PUD #1	1.7582%	$ 92,471	0.0000%	$ -
10103	Clark County PUD #1	8.0074%	$ 421,149	0.0000%	$ -
10105	Clatskanie PUD	0.8243%	$ 43,356	4.3111%	$ 66,311
10106	Clearwater Power	0.0000%	$ -	0.3634%	$ 5,590
10109	Columbia Basin Elec Coop	0.0000%	$ -	0.0000%	$ -
10111	Columbia Power Coop	0.0000%	$ -	0.0000%	$ -
10113	Columbia REA	0.0000%	$ -	0.0000%	$ -
10112	Columbia River PUD	0.8965%	$ 47,151	0.0000%	$ -
10116	Consolidated Irrigation District #19	0.0062%	$ 324	0.0000%	$ -
10118	Consumers Power	0.0000%	$ -	0.6416%	$ 9,869
10121	Coos Curry Elec Coop	0.0000%	$ -	0.5864%	$ 9,021
10378	Coulee Dam, City of	0.0000%	$ -	0.0000%	$ -
10123	Cowlitz County PUD #1	11.6409%	$ 612,255	0.0000%	$ -
10070	Declo, City of	0.0000%	$ -	0.0000%	$ -
10136	Douglas Electric Cooperative	0.0000%	$ -	0.2881%	$ 4,431
10071	Drain, City of	0.0645%	$ 3,391	0.0000%	$ -
10142	East End Mutual Electric	0.0000%	$ -	0.0000%	$ -
10144	Eatonville, Town of	0.0785%	$ 4,128	0.0000%	$ -
10072	Ellensburg, City of	0.5916%	$ 31,117	0.0000%	$ -
10156	Elmhurst Mutual P & L	0.0000%	$ -	0.0000%	$ -
10157	Emerald County PUD	1.2717%	$ 66,886	0.0000%	$ -
10158	Energy Northwest	0.0689%	$ 3,626	0.0000%	$ -
10170	Eugene Water & Electric Board	1.8882%	$ 99,311	10.7514%	$ 165,374
10172	Fairchild AFB	0.2042%	$ 10,740	0.0000%	$ -
10173	Fall River Elec Coop	0.0000%	$ -	0.3245%	$ 4,991
10174	Farmers Electric Company	0.0000%	$ -	0.0000%	$ -
10177	Ferry County PUD #1	0.2292%	$ 12,057	0.0000%	$ -
10179	Flathead Elec Coop	2.0537%	$ 108,013	0.0000%	$ -
10074	Forest Grove, City of	0.5712%	$ 30,044	0.0000%	$ -
10183	Franklin County PUD #1	0.5792%	$ 30,464	3.4696%	$ 53,369

This sheet calculates Slice credits for PNGC members only on their retained slice percentages the bulk is refunded to PNGC

Total FY 2010-2011 Lookback Credit Amount	**$**	**163,144,416**
Slice FY 2010-2011 Lookback Credit Amount	$	36,915,992
Non-Slice FY 2010-2011 Lookback Credit Amount	$	126,228,424

	Customer Name	**Non-Slice PF-02 Revenue Share**		**Non-Slice Monthly FY10-11 Lookback Credit Amount**	**Slice % Share**		**Slice Monthly FY10-11 Lookback Credit Amount**
10186	Glacier Elec Coop	0.0000%	$	-	0.0000%	$	-
10190	Grant County PUD #2	3.8707%	$	203,579	0.0000%	$	-
10191	Grays Harbor PUD #1	0.9788%	$	51,478	5.1622%	$	79,404
10197	Harney Elec Coop	0.3086%	$	16,232	0.0000%	$	-
10597	Hermiston, City of	0.3383%	$	17,792	0.0000%	$	-
10076	Heyburn, City of	0.1707%	$	8,981	0.0000%	$	-
10202	Hood River Elec Coop	0.3032%	$	15,948	0.0000%	$	-
10203	Idaho County L & P	0.1317%	$	6,929	0.0000%	$	-
10204	Idaho Falls Power	0.5742%	$	30,202	3.0630%	$	47,115
10209	Inland P & L	0.0000%	$	-	0.0000%	$	-
10230	Kittitas County PUD #1	0.1623%	$	8,537	0.0000%	$	-
10231	Klickitat County PUD #1	0.7404%	$	38,943	0.0000%	$	-
10234	Kootenai Electric Coop	0.0000%	$	-	0.0000%	$	-
10235	Lakeview L & P (WA)	0.8847%	$	46,530	0.0000%	$	-
10236	Lane County Elec Coop	0.0000%	$	-	0.4182%	$	6,433
10237	Lewis County PUD #1	2.4335%	$	127,991	0.0000%	$	-
10239	Lincoln Elec Coop (MT)	0.0000%	$	-	0.0000%	$	-
10242	Lost River Elec Coop	0.0000%	$	-	0.1085%	$	1,670
10244	Lower Valley Energy	0.0000%	$	-	0.0000%	$	-
10246	Mason County PUD #1	0.1759%	$	9,253	0.0000%	$	-
10247	Mason County PUD #3	1.8376%	$	96,651	0.0000%	$	-
10078	McCleary, City of	0.1201%	$	6,319	0.0000%	$	-
10079	McMinnville, City of	2.0046%	$	105,435	0.0000%	$	-
10256	Midstate Elec Coop	0.9701%	$	51,023	0.0000%	$	-
10081	Milton Freewater, City of	0.2599%	$	13,671	0.0000%	$	-
10080	Milton, City of	0.1814%	$	9,540	0.0000%	$	-
10082	Minidoka, City of	0.0000%	$	-	0.0000%	$	-
10258	Mission Valley	0.0000%	$	-	0.0000%	$	-
10259	Missoula Elec Coop	0.0000%	$	-	0.0000%	$	-
10260	Modern Elec Coop	0.0000%	$	-	0.0000%	$	-
10083	Monmouth, City of	0.2013%	$	10,587	0.0000%	$	-
10273	Nespelem Valley Elec Coop	0.1194%	$	6,278	0.0000%	$	-
10278	Northern Lights	0.0000%	$	-	0.2836%	$	4,363
10279	Northern Wasco County PUD	0.5714%	$	30,052	0.0000%	$	-
10284	Ohop Mutual Light Company	0.0000%	$	-	0.0000%	$	-
10285	Okanogan County Elec Coop	0.0000%	$	-	0.0805%	$	1,239
10286	Okanogan County PUD #1	0.3815%	$	20,068	2.1880%	$	33,655
10288	Orcas P & L	0.0000%	$	-	0.0000%	$	-
10291	Oregon Trail Coop	1.8092%	$	95,153	0.0000%	$	-
10294	Pacific County PUD #2	0.8897%	$	46,793	0.0000%	$	-
10304	Parkland L & W	0.0000%	$	-	0.0000%	$	-
10306	Pend Oreille County PUD #1	0.2444%	$	12,854	1.6877%	$	25,960
10307	Peninsula Light Company	1.6355%	$	86,018	0.0000%	$	-
10086	Plummer, City of	0.0954%	$	5,019	0.0000%	$	-
10298	PNGC	3.0927%	$	162,661	12.3742%	$	190,335
10087	Port Angeles, City of	1.7466%	$	91,865	0.0000%	$	-
10706	Port of Seattle	0.0000%	$	-	0.0000%	$	-
10326	Puget Sound Naval Shipyard (Bremerton)	0.7328%	$	38,542	0.0000%	$	-
10331	Raft River Elec Coop	0.0000%	$	-	0.1745%	$	2,684
10333	Ravalli County Elec Coop	0.0000%	$	-	0.0000%	$	-
10089	Richland, City of	2.1063%	$	110,780	0.0000%	$	-

This sheet calculates Slice credits for PNGC members only on their retained slice percentages the bulk is refunded to PNGC

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	Customer Name	**Non-Slice PF-02 Revenue Share**	**Non-Slice Monthly FY10-11 Lookback Credit Amount**	**Slice % Share**	**Slice Monthly FY10-11 Lookback Credit Amount**
10338	Riverside Elec Company	0.0000%	$ -	0.0000%	$ -
10091	Rupert, City of	0.2463%	$ 12,957	0.0000%	$ -
10342	Salem Elec Coop	1.1566%	$ 60,832	0.0000%	$ -
10343	Salmon River Elec Coop	0.0000%	$ -	0.3468%	$ 5,335
10349	Seattle City Light	3.4466%	$ 181,274	20.6277%	$ 317,289
10352	Skamania County PUD #1	0.3730%	$ 19,621	0.0000%	$ -
10354	Snohomish County PUD #1	8.3895%	$ 441,249	22.0653%	$ 339,402
10094	Soda Springs, City of	0.0000%	$ -	0.0000%	$ -
11342	Southern MT G&T	0.0000%	$ -	0.0000%	$ -
10360	South Side Electric	0.0000%	$ -	0.0000%	$ -
10363	Springfield Utility Board	1.6574%	$ 87,169	0.0000%	$ -
10379	Steilacoom, Town of	0.1200%	$ 6,311	0.0000%	$ -
10095	Sumas, City of	0.0791%	$ 4,162	0.0000%	$ -
10369	Surprise Valley Elec Coop	0.2762%	$ 14,526	0.0000%	$ -
10370	Tacoma Public Utilities	10.0610%	$ 529,160	0.0000%	$ -
10371	Tanner Elec Coop	0.2006%	$ 10,553	0.0000%	$ -
10376	Tillamook PUD #1	0.9711%	$ 51,073	0.0000%	$ -
10097	Troy, City of	0.0000%	$ -	0.0000%	$ -
10406	U.S. DOE Albany	0.0112%	$ 587	0.0000%	$ -
10408	U.S. Naval Station, Everett (Jim Creek)	0.0364%	$ 1,915	0.0000%	$ -
10409	U.S. Naval Submarine Base, Bangor	0.5118%	$ 26,919	0.0000%	$ -
10388	Umatilla Elec Coop	0.0000%	$ -	1.4473%	$ 22,262
10482	Umpqua Indian Utility Cooperative	0.0530%	$ 2,785	0.0000%	$ -
10391	United Electric Coop	0.4869%	$ 25,606	0.0000%	$ -
10399	USBIA Wapato	0.0170%	$ 897	0.0000%	$ -
10426	USDOE-Richland	0.6531%	$ 34,351	0.0000%	$ -
10434	Vera Irrigation District	0.6434%	$ 33,837	0.0000%	$ -
10436	Vigilante Elec Coop	0.0000%	$ -	0.0000%	$ -
10440	Wahkiakum County PUD #1	0.1098%	$ 5,776	0.0000%	$ -
10442	Wasco Elec Coop	0.0000%	$ -	0.0000%	$ -
11680	Weiser, City of	0.0000%	$ -	0.0000%	$ -
10446	Wells Rural Electric Company	1.3121%	$ 69,010	0.0000%	$ -
10448	West Oregon Elec Coop	0.0000%	$ -	0.1344%	$ 2,068
10451	Whatcom County PUD #1	0.6078%	$ 31,970	0.0000%	$ -
10502	Yakama Power	0.0096%	$ 506	0.0000%	$ -
		0.0000%	$ -	0.0000%	$ -
	TOTAL	100.0000%	$ 5,259,521	100.0000%	$ 1,538,170

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