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

BP-16 Rate Proceeding

ADMINISTRATOR'S FINAL RECORD OF DECISION

Appendix B: Power Rate Schedules and General Rate Schedule Provisions

BP-16-A-02-AP02

July 2015

BONNEVILLE POWER ADMINISTRATION

POWER RATE SCHEDULES

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Appendices

COMMONLY USED ACRONYMS AND SHORT FORMS

ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CIR	Capital Investment Review
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DNR	Designated Network Resource
DOE	Department of Energy
DOI	Department of Interior
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EE	Energy Efficiency
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
ESA	Endangered Species Act
ESS	Energy Shaping Service
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System

FELCC	firm energy load carrying capability
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GMS	Grandfathered Generation Management Service
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IM	Montana Intertie
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power
IPR	Integrated Program Review
IR	Integration of Resources
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRMP	Irrigation Rate Mitigation Product
IS	Southern Intertie
kcfs	thousand cubic feet per second
kW	kilowatt
kWh	kilowatthour
LDD	Low Density Discount
LLH	Light Load Hour(s)
LPP	Large Project Program
LPTAC	Large Project Targeted Adjustment Charge
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MRNR	Minimum Required Net Revenue
MW	megawatt
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	**N**ational Marine Fisheries Service (NMFS) **F**ederal Columbia River Power System (FCRPS) **B**iological Opinion (BiOp)
NIFC	Northwest Infrastructure Financing Corporation
NLSL	New Large Single Load

NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NP-15	North of Path 15
NPCC	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NT	Network Integration
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OATI	Open Access Technology International, Inc.
OMP	Oversupply Management Protocol
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
Peak	Peak Reliability
PF	Priority Firm Power
PFIA	Projects Funded in Advance
PFp	Priority Firm Public
PFx	Priority Firm Exchange
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
POR	Point of Receipt
Project Act	Bonneville Project Act
PRS	Power Rates Study
PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point to Point
PUD	public or people’s utility district
PW	WECC and Peak Service
RAM	Rate Analysis Model (computer model)
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement

RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
SCD	Scheduling, System Control, and Dispatch rate
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TGT	Townsend-Garrison Transmission
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
Treaty	Columbia River Treaty
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
ULS	Unanticipated Load Service
USACE	U.S. Army Corps of Engineers
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish & Wildlife Service
VERBS	Variable Energy Resources Balancing Service
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period (PF Tier 2 rate)
VR1-2016	First Vintage Rate of the BP-16 rate period (PF Tier 2 rate)
WECC	Western Electricity Coordinating Council
WSPP	Western Systems Power Pool

POWER RATE SCHEDULES

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POWER RATE SCHEDULES

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SCHEDULE PF-16
PRIORITY FIRM POWER RATE

1 Availability

This schedule is available for the contract purchase of Firm Requirements Power pursuant to section 5(b) of the Northwest Power Act. Firm Requirements Power may be purchased for use within the Pacific Northwest 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.

Utilities participating in the Residential Exchange Program under section 5(c) of the Northwest Power Act may purchase Residential Exchange Program Power pursuant to a Residential Purchase and Sale Agreement or Residential Exchange Program Settlement Implementation Agreement.

With the exception of sales under the Residential Exchange Program, transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2015, this rate schedule supersedes the PF-14 rate schedule. Sales under the PF-16 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2 Priority Firm Public Rate

The PF Public Rate is applicable to the sale of Firm Requirements Power under CHWM Contracts for Load Following, Block, and Slice/Block power products.

2.1 Tier 1 Charges

Tier 1 charges for each customer include two of three Customer charges, a Demand charge, and a Load Shaping charge.

2.1.1 Customer Charges

The Customer Charges are applicable to Customers that purchase the following products: Load Following, Block, and Slice/Block.

2.1.1.1 Customer Rates

The monthly Composite, Non-Slice, and Slice Customer rates are specified in the following table:

	Customer Charge Rate in dollars per percentage point of billing determinant		
	Composite	***Non-Slice***	***Slice***
Customer Rate	2,062,767	(306,652)	0

2.1.1.2 Customer Billing Determinants

The Composite, Non-Slice, and Slice Customer billing determinants are specified in the following table:

	Customer Charge Billing determinant for each rate		
	Composite	***Non-Slice***	***Slice***
Load Following	TOCA	TOCA	N/A
Block only	TOCA	TOCA	N/A
Block portion of Slice/Block	Non-Slice TOCA	Non-Slice TOCA	N/A
Slice portion of Slice/Block	Slice %	N/A	Slice %

N/A = Not Applicable

Where:
TOCA = Tier 1 Cost Allocator, expressed as a percentage

For each Customer for each Fiscal Year of the Rate Period, the TOCA shall be calculated according to the following formula:

$$\frac{\textit{Minimum of the Customer's: a) RHWM, or b) Forecast Net Requirement for each Fiscal Year}}{\textit{Sum of all Customers' RHWMs}} \times 100$$

The TOCA for a Joint Operating Entity (JOE) is the sum of the TOCAs of the individual members of the JOE.

All Customer TOCAs shall be posted on the BPA Web site. A Customer's TOCA may be revised pursuant to the TOCA Adjustment, GRSP II.Y.

Slice % = The Slice percentage for the relevant Fiscal Year as specified in Exhibit K of the Slice Customer's CHWM Contract.

Non-Slice TOCA = TOCA minus Slice %, expressed as a percentage.

A Customer's Non-Slice TOCA may be revised pursuant to the TOCA Adjustment, GRSP II.Y.

2.1.2 Demand Charge

The Demand Charge is applicable to Customers that purchase the following products: Load Following and Block with Shaping.

2.1.2.1 Demand Rate

Month	***Rate in $/kW***
October	10.02
November	10.27
December	10.51
January	10.79
February	10.66
March	9.13
April	8.76
May	7.95
June	8.33
July	9.87
August	10.90
September	11.42

2.1.2.2 Demand Billing Determinant

The Demand billing determinant for each billing month equals:

Tier 1 CSP – aHLH – CDQ – SuperPeak

Where:

Tier 1 CSP = Tier 1 Customer System Peak; the Customer's maximum Actual Hourly Tier 1 Load during the Heavy Load Hours of the month, in kilowatts

HLH = Average of the Customer's Actual Hourly Tier 1 Loads during the HLH, in kilowatts

CDQ = Contract Demand Quantity specified in the Customer's CHWM Contract, Exhibit B, section 2, in kilowatts

SuperPeak = Super Peak Credit, if any, specified in the Customer's CHWM Contract, Exhibit A, section 9, in kilowatts

If the Demand Charge billing determinant calculation results in a value less than zero, the billing determinant is deemed to be zero.

The Demand billing determinant may be adjusted pursuant to GRSP II.D.

If a Customer purchases Secondary Crediting Service, the Demand billing determinant may be adjusted pursuant to GRSP II.U.2.

2.1.3 Load Shaping Charge

The Load Shaping Charge is applicable to Customers that purchase the following products: Load Following, Block, and the Block portion of Slice/Block. In any diurnal period (HLH or LLH), the Load Shaping Charge may be a charge or a credit, depending upon whether the Load Shaping billing determinant is positive or negative.

2.1.3.1 Load Shaping Rate

Month	*Rate in mills/kWh*	
	HLH	*LLH*
October	$27.86	$23.75
November	$28.56	$24.48
December	$29.22	$24.82
January	$30.02	$25.03
February	$29.65	$24.68
March	$25.38	$22.07
April	$24.36	$21.04
May	$22.10	$17.53
June	$23.15	$17.11
July	$27.43	$21.58
August	$30.30	$24.41
September	$31.75	$25.70

2.1.3.2 Load Shaping Billing Determinant

The Load Shaping billing determinant for each of the two diurnal periods, HLH and LLH, for each month equals:

Customer's Actual Monthly/Diurnal Tier 1 Load,
in kilowatthours
Minus
Customer's System Shaped Load for the relevant diurnal period,
in kilowatthours

If a Customer purchases Secondary Crediting Service (SCS), the Load Shaping billing determinant may be adjusted pursuant to GRSP II.U.2.

2.1.3.2.1 System Shaped Load

A System Shaped Load is calculated for each diurnal period of each month. The Customer's System Shaped Load for each diurnal period equals:

$RT1SC \times TOCA$

Where:

RT1SC = RHWM Tier 1 System Capability for the relevant diurnal period, in kilowatthours. The RT1SC for each diurnal period of the Rate Period is specified in GRSP II.V.

TOCA = The effective TOCA for a Load Following or Block Customer, or the effective Non-Slice TOCA for a Slice/Block Customer, expressed as a percentage. The TOCA used in this System Shaped Load calculation shall reflect a Customer's Adjusted TOCA pursuant to GRSP II.Y.

2.1.3.2.2 Joint Operating Entity (JOE)

For calculating the Load Shaping Charge billing determinant for a JOE, the sum of the Actual Monthly/Diurnal Tier 1 Loads of the JOE's individual members and the sum of System Shaped Loads of the JOE's individual members shall be used.

2.1.4 Slice Billing Adjustment

Customers that purchased the Slice Product during the period FY 2012–2015 are subject to a billing adjustment in FY 2016.

The billing adjustment shall appear on the Customer's November 2015 power bill.

The adjustment amount for each Customer is set forth in Appendix C to the General Rate Schedule Provisions.

2.2 Tier 2 Charges

2.2.1 Tier 2 Load Shaping Charge

Pursuant to section 4.3 of the Tiered Rate Methodology, BP-12-A-03, the Tier 2 Load Shaping charge is applicable to customers that have elected to serve Above-RHWM Load with purchases at Tier 2 rates and are forecast to have Above-RHWM Load less than 8,760 MWh.

2.2.1.1 Tier 2 Load Shaping Rates

The Tier 2 Load Shaping Rates shall be the rates specified in section 2.1.3.1.

2.2.1.2 Tier 2 Load Shaping Billing Determinant

The Tier 2 Load Shaping billing determinant for each billing period is incorporated into the billing determinant established in section 2.1.3.2.

2.2.2 Short-Term Charge

The Short-Term Charge is applicable to Customers that have elected to purchase power at the Tier 2 Short-Term Rate, as specified in the Customer's CHWM Contract, Exhibit C, section 2.5.2.

2.2.2.1 Short-Term Rate

Fiscal Year	***Rate in mills/kWh***
2016	29.72
2017	32.01

2.2.2.2 Short-Term Billing Determinant

The billing determinant is the annual amount of power specified in the Customer's CHWM Contract. For the relevant billing month, the contract amount shall be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

2.2.3 Load Growth Charge

The Load Growth Charge is applicable to Customers that have elected to purchase power at the Tier 2 Load Growth Rate, as specified in the Customers' CHWM Contracts, Exhibit C, section 2.5.2.

2.2.3.1 Load Growth Rate

Fiscal Year	***Rate in mills/kWh***
2016	45.18
2017	49.60

2.2.3.2 Load Growth Billing Determinant

The billing determinant is the annual amount of power specified in the Customer's CHWM Contract. For the relevant billing month, the contract amount shall be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

2.2.3.3 Load Growth Rate Customer Charge

Load Growth Rate Customers are subject to a customer charge for FY 2016 and FY 2017.

The monthly amounts charged to each Customer are set forth in Appendix B to the General Rate Schedule Provisions.

2.2.4 VR1-2014 Charge

The VR1-2014 Charge is applicable to Customers that elected to purchase power at the Tier 2 VR1-2014 Rate, as specified in the Customers' CHWM Contracts, Exhibit C, section 2.5.2.

2.2.4.1 VR1-2014 Rate

Fiscal Year	***Rate in mills/kWh***
2016	44.72
2017	49.08

2.2.4.2 VR1-2014 Billing Determinant

The billing determinant is the annual amount of power specified in the Customer's CHWM Contract. For the relevant billing month, the contract amount shall be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

2.2.5 VR1-2016 Charge

The VR1-2016 Charge is applicable to Customers that have elected to purchase power at the Tier 2 VR1-2016 Rate, as specified in the Customers' CHWM Contracts, Exhibit C, section 2.5.2.

2.2.5.1 VR1-2016 Rate

Fiscal Year	***Rate in mills/kWh***
2016	40.60
2017	43.18

2.2.5.2 VR1-2016 Billing Determinant

The billing determinant is the annual amount of power specified in the Customer's CHWM Contract. For the relevant billing month, the contract amount shall be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

3 Priority Firm Melded Rate

The PF Melded rate is applicable to the sale of Firm Requirements Power under contracts other than CHWM Contracts.

Rates under contracts that contain charges that escalate based on BPA's PF rate shall be based on the rates listed in this section in addition to any applicable transmission and ancillary service charges.

The PF Melded rate is not available to loads that are considered unanticipated loads as defined in Unanticipated Load Service, GRSP II.Z.1.

3.1 Energy Charge

3.1.1 Energy Rate

Month	***Rate in mills/kWh***	
	HLH	***LLH***
October	36.47	32.36
November	37.17	33.09
December	37.83	33.43
January	38.63	33.64
February	38.26	33.29
March	33.99	30.68
April	32.97	29.65
May	30.71	26.14
June	31.76	25.72
July	36.04	30.19
August	38.91	33.02
September	40.36	34.31

3.1.2 Energy Billing Determinant

The Energy billing determinant is the total of the hourly loads, as specified in the Customer's contract, for each diurnal period, in kilowatthours.

3.2 Demand Charge

3.2.1 Demand Rate

Month	***Rate in $/kW***
October	10.02
November	10.27
December	10.51
January	10.79
February	10.66
March	9.13
April	8.76
May	7.95
June	8.33
July	9.87
August	10.90
September	11.42

3.2.2 Demand Billing Determinant

The Demand billing determinant is the maximum hourly load, as specified in the Customer's contract, during the HLH of the month, in kilowatts, less the average of the hourly loads during the HLH of the month, in kilowatts.

4 Unanticipated Load Service Charge

The Unanticipated Load Service charge is applicable to the sale of Firm Requirements Power to serve unanticipated loads. The billing determinant for an unanticipated load and the applicable rates are specified in Unanticipated Load Service, GRSP II.Z.2.

5 Resource Support Services Rates

Resource Support Services rates are applicable to Customers that elect to take Diurnal Flattening Service, Secondary Crediting Service, or Grandfathered Generation Management Service for non-Federal resources. The Resource Shaping Charge and Adjustment are applicable to Customers that elect this option to financially convert the output of certain types of non-Federal resources to a flat annual block of power as specified in their CHWM Contracts.

5.1 Diurnal Flattening Service (DFS)

Customers that have elected to take DFS for their non-Federal resources are subject to the DFS Energy and Capacity Charges, specified in GRSP II.U.1.

5.2 Resource Shaping Charge and Adjustment

Customers that have elected to take this option for their new resources, other than small non-dispatchable resources, are subject to the Resource Shaping Charge and Adjustment, specified in GRSP II.U.1.

5.3 Secondary Crediting Service (SCS)

Customers that have elected to take SCS for their non-Federal resources are subject to the SCS Shortfall Energy Charge, SCS Secondary Energy Charge, and SCS Administrative Charge, specified in GRSP II.U.2.

5.4 Grandfathered Generation Management Service (GMS)

Load Following Customers dedicating the entire output of an Existing Resource that received GMS under Subscription to their Tier 1 Load are subject to a GMS Reservation Fee, specified in GRSP II.U.5.

6 Priority Firm Exchange Rate

The PF Exchange rate applies to sales of Residential Exchange Program Power under a Residential Purchase and Sale Agreement or Residential Exchange Program Settlement Implementation Agreement.

6.1. Energy Rate

A utility-specific PF Exchange rate is calculated for each utility purchasing Residential Exchange Program Power. For investor-owned utilities, the PF Exchange rate equals the Base PF Exchange rate plus a utility-specific 7(b)(3) Surcharge. For consumer-owned utilities, the PF Exchange rate equals the Base Tier 1 PF Exchange rate plus a utility-specific 7(b)(3) Surcharge.

	Rates in mills/kWh		
Investor-Owned Utilities	***Base PF Exchange Rates***	***7(b)(3) Surcharge***	***PF Exchange Rates***
Avista	47.95	2.60	50.54820
Idaho Power	47.95	9.56	57.51170
NorthWestern	47.95	21.05	68.99820
PacifiCorp	47.95	21.26	69.20550
Portland General	47.95	16.00	63.95300
Puget Sound Energy	47.95	13.21	61.15820
Consumer-Owned Utilities	***Base Tier 1 PF Exchange Rates***	***7(b)(3) Surcharge***	***PF Exchange Rates***
Clark Public Utilities	47.98	1.87	49.85
Snohomish County PUD No 1	47.98	1.01	48.99

6.1.1 7(b)(3) Surcharge for Non-Listed Utilities

For eligible Customers not listed in section 6.1, the applicable 7(b)(3) Surcharge shall equal the Customer's Average System Cost minus the applicable Base PF Exchange rate. The Customer's Average System Cost shall be determined pursuant to BPA's 2008 Average System Cost Methodology.

6.2 Energy Billing Determinant

The billing determinant for the PF Exchange Power charge is the Customer's Residential Load specified in GRSP II.S., Table E.

7 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable to PF rates as shown in the following tables.

		Applicable to:			
		Firm Requirements			
GRSP II.	***Adjustments, Charges, and Special Rate Provisions***	***Load Following***	***Block only and Block Portion of Slice/Block***	***Slice Portion of Slice/Block***	***REP***
A.1	Conservation Surcharge	X	X	X	
A.2	Large Project Targeted Adjustment Charge	X	X	X	
B	Cost Contributions	X	X		
C	Cost Recovery Adjustment Clause (CRAC)	X	X		
D	Demand Rate Billing Determinant Adjustments	X	X		
E	Dividend Distribution Clause (DDC)	X	X		
I	Flexible Priority Firm Power (PF) Rate Option	X	X		
J	General Transfer Agreement Service Charges	X	X	X	
K	Irrigation Rate Discount	X	X	X	
L	Load Shaping Charge Adjustment	X	X		
M	Low Density Discount (LDD)	X	X	X	
N	NFB Mechanisms	X	X		
P	Priority Firm Power (PF) Shaping Option	X	X		
R	Remarketing	X	X		
S	Residential Exchange Program Residential Load				X
T	Residential Exchange Program 7(b)(3) Surcharge Adjustment				X
U	Resource Support Services and Transmission Scheduling Service	X	X	X	
V	RHWM Tier 1 System Capability (RT1SC)	X	X		
W	Slice True-Up Adjustment			X	
X	Tier 2 Rate TCMS Adjustment	X			
Y	TOCA Adjustment	X	X		
Z	Unanticipated Load Service	X	X		
AA	Unauthorized Increase (UAI) Charge	X	X	X	X

GRSP Appendix	***Adjustments***	***Load Following***	***Block only and Block Portion of Slice/Block***	***Slice Portion of Slice/Block***	***Tier 2***
A	REP Settlement Customer Refund Amounts in FY 2016-2017	X	X	X	
B	Tier 2 Load Growth Rate Customer Charge for FY 2016-2017				X
C	Slice Billing Adjustment			X	

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SCHEDULE NR-16
NEW RESOURCE FIRM POWER RATE

1 Availability

This schedule is available for the contract purchase of firm power to be used within the Pacific Northwest. 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. New Resource Firm Power 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. This schedule is available for services provided to Load Following customers that are serving NLSLs with non-Federal resources.

Transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2015, this rate schedule supersedes the NR-14 rate schedule. Sales under the NR-16 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2 New Resource Rates

2.1 Energy Charge

2.1.1 Energy Rate

Month	*Rate in mills/kWh*	
	HLH	***LLH***
October	76.33	72.22
November	77.03	72.95
December	77.69	73.29
January	78.49	73.50
February	78.12	73.15
March	73.85	70.54
April	72.83	69.51
May	70.57	66.00
June	71.62	65.58
July	75.90	70.05
August	78.77	72.88
September	80.22	74.17

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects a REP Surcharge of 8.20 mills/kWh.

2.1.2 Energy Billing Determinant

The billing determinant is the total of NR Hourly Loads for each diurnal period.

2.2 Demand Charge

2.2.1 Demand Rate

Month	*Rate in $/kW*
October	10.02
November	10.27
December	10.51
January	10.79
February	10.66
March	9.13
April	8.76
May	7.95
June	8.33
July	9.87
August	10.90
September	11.42

2.2.2 Demand Billing Determinant

The billing determinant is the highest NR Hourly Load during HLH, in kilowatts, for the billing period minus the average of the NR Hourly Load during the HLH, in kilowatts.

3 Unanticipated Load Service Charge

The Unanticipated Load Service charge is applicable to the sale of Firm Requirements Power to serve unanticipated loads. The billing determinant for an unanticipated load and the applicable rates are specified in GRSP II.Z.3.

4 Energy Shaping Service for New Large Single Loads (NLSLs) Charge

The Energy Shaping Service (ESS) for NLSLs Charge, specified in GRSP II.G.1, is applicable to Load Following Customers that serve NLSLs with non-Federal resources.

5 NR Resource Flattening Service Charge

The NR Resource Flattening Service charge, specified in GRSP II.G.2, is applicable to Load Following Customers that apply the generation output of a non-dispatchable Specified Resource to serve an NLSL.

6 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following table.

Adjustments, Charges, and Special Rate Provisions	*GRSP II.*
Conservation Surcharge	A.1
Cost Contributions	B
Cost Recovery Adjustment Clause (CRAC)	C
Demand Rate Billing Determinant Adjustments	D
Dividend Distribution Clause (DDC)	E
Energy Shaping Service for NLSLs Charge	G.1
NR Resource Flattening Service Charge	G.2
Flexible New Resource Firm Power (NR) Rate Option	H
Low Density Discount (LDD)	M
NFB Mechanisms	N
Unanticipated Load Service	Z
Unauthorized Increase (UAI) Charge	AA

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SCHEDULE IP-16
INDUSTRIAL FIRM POWER RATE

1 Availability

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

Transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2015, this rate schedule supersedes the IP-14 rate schedule. Sales under the IP-16 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

DSIs purchasing power pursuant to the IP-16 rate schedule shall be required to provide the Minimum DSI Operating Reserve – Supplemental.

2 Industrial Firm Rates

2.1 Energy Charge

2.1.1 Energy Rates

Month	***Rate in mills/kWh***	
	HLH	***LLH***
October	44.43	40.32
November	45.13	41.05
December	45.79	41.39
January	46.59	41.60
February	46.22	41.25
March	41.95	38.64
April	40.93	37.61
May	38.67	34.10
June	39.72	33.68
July	44.00	38.15
August	46.87	40.98
September	48.32	42.27

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects a REP Surcharge of 8.20 mills/kWh.

2.1.1.2 Value of Reserves Credit

Each energy rate in the table above reflects a 0.973 mills/kWh credit for the value of the Minimum DSI Operating Reserve – Supplemental.

2.1.2 Energy Billing Determinant

The billing determinant is the Energy Entitlement that is specified in the Customer’s contract.

2.2 Demand Charge

2.2.1 Demand Rate

Month	***Rate in $/kW***
October	10.02
November	10.27
December	10.51
January	10.79
February	10.66
March	9.13
April	8.76
May	7.95
June	8.33
July	9.87
August	10.90
September	11.42

2.2.2 Demand Billing Determinant

The billing determinant is the Customer’s maximum schedule amount during HLH, in kilowatts, for the billing period minus the average of the Customer’s monthly schedule amount during the HLH, minus the Industrial Demand Adjuster, if any, in kilowatts.

Port Townsend Paper Corporation's Industrial Demand Adjuster values are specified in the table below.

Month	***Industrial Demand Adjuster (kW)***
October	2046
November	1646
December	1160
January	1019
February	1115
March	1598
April	795
May	1122
June	763
July	793
August	903
September	731

If Port Townsend Paper's Contract Demand is other than 15.75 MW, the Industrial Demand Adjuster values in the above table shall be adjusted proportionally.

If the Demand Charge billing determinant calculation results in a value less than zero, the billing determinant is deemed to be zero.

3 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following table.

Adjustments, Charges, and Special Rate Provisions	***GRSP II.***
Conservation Surcharge	A.1
Cost Contributions	B
Cost Recovery Adjustment Clause (CRAC)	C
Demand Rate Billing Determinant Adjustments	D
Dividend Distribution Clause (DDC)	E
DSI Reserves Adjustment	F
NFB Mechanisms	N
Unauthorized Increase (UAI) Charge	AA

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SCHEDULE FPS-16
FIRM POWER AND SURPLUS PRODUCTS AND SERVICES RATE

1 Availability

This rate schedule is available for the sale of Firm Power (capacity and/or energy), Capacity Without Energy, Shaping Services, Reservation and Rights to Change Services, Reassignment or Remarketing of Surplus Transmission Capacity, Services for Non-Federal Resources, Unanticipated Load Service, and other capacity, energy, and power scheduling products and services for use inside and outside the Pacific Northwest.

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, or 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, 2015, this rate schedule supersedes the FPS-14 rate schedule. Sales under the FPS-16 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2 Firm Power and Capacity Without Energy

2.1 Flexible Rates and Billing Determinants

Demand and/or energy charges shall be as specified by BPA or as mutually agreed by BPA and the Customer. Billing determinants shall be Contract Demand and Contract Energy unless otherwise agreed by BPA and the Customer.

3 Shaping Services

3.1 Rates and Billing Determinants

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

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

4 Reservations and Rights to Change Services

4.1 Rates and Billing Determinants

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

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

5 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).

5.1 Rates and Billing Determinants

The charges for Reassignment or Remarketing of Surplus Transmission Capacity shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the Customer.

The rate(s) and billing determinant(s) for Reassignment or Remarketing of Surplus Transmission Capacity shall be as established by BPA or as mutually agreed to by BPA and the Customer.

6 Services for Non-Federal Resources

6.1 Transmission Scheduling Service/Transmission Curtailment Management Service (TSS/TCMS)

Customers that have elected to take TSS/TCMS for their non-Federal resources are subject to the TSS and TCMS Charges specified in GRSP II.U.4.

6.2 Forced Outage Reserve Service (FORS)

Customers that have elected to take FORS for their non-Federal resources are subject to the FORS Energy and Capacity Charges specified in GRSP II.U.3.

6.3 Resource Remarketing Service (RRS)

Customers that have requested and have been granted permission to take RRS for their non-Federal resources shall receive the RRS credit specified in GRSP II.U.6.

7 Unanticipated Load Service

The Unanticipated Load Service is applicable to the sale of firm power to serve unanticipated loads resulting from a request for service under section 9(i) of the Northwest Power Act. The billing determinant for an unanticipated load and the applicable rates are specified in GRSP II.Z.4.

8 Other Capacity, Energy, and Scheduling Products and Services

Power Services may sell energy or capacity (including energy or capacity provided to balancing authorities and transmission providers, other than the BPA Balancing Authority, for use as ancillary services) and power scheduling products and services under this rate schedule. Such products and services may include, but are not limited to: (1) interruptible energy; (2) resource support and scheduling services for non-Federal resources not eligible for services under section 6 of this FPS rate schedule; and (3) reserve-based products and services (including but not limited to operating reserves, imbalance energy, frequency response reserves and regulation for use outside the BPA Balancing Authority Area).

8.1 Rates and Billing Determinants

Rate(s) and billing determinant(s) applicable to such products and services shall be as specified by BPA or as agreed to by BPA and the Customer. The charge(s) for these services shall be the applicable rate(s) times the applicable billing determinant(s) pursuant to the agreement between BPA and the Customer.

9 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following table and/or as specified by BPA or as agreed to by BPA and the Customer.

Adjustments, Charges, and Special Rate Provisions	***GRSP II.***
Cost Contributions	B
Unauthorized Increase (UAI) Charge	AA

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GENERAL RATE SCHEDULE PROVISIONS

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GENERAL RATE SCHEDULE PROVISIONS

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Appendices

GENERAL RATE SCHEDULE PROVISIONS

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

A. Approval of Rates

The 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 (Commission). BPA will request that the Commission make these rates and GRSPs effective on October 1, 2015. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

The Power rate schedules and GRSPs associated with the rate schedules supersede BPA's 2014 Power rate schedules, which became effective October 1, 2013, 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 (Pub. L. No. 75-329), the Regional Preference Act (Pub. L. No. 88-552), the Transmission System Act (Pub. L. No. 93-454), the Northwest Power Act (Pub. L. No. 96-501), and the Energy Policy Act of 1992 (Pub. L. No. 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. After the Due Date, a late payment charge equal to the higher of (1) the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which payment was due) plus four percent, divided by 365; or (2) the Prime Rate times 1.5, divided by 365, shall be applied each day to any unpaid balance. 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 "Facility Ownership and Cost Assignment Guidelines," as amended or superseded (Transmission Services Guidelines), currently posted at:
http://www.bpa.gov/transmission/Doing%20Business/Interconnection/Documents/BPA_Facility_Ownership_and_Cost_Assignment_Guidelines.pdf

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.

Supplemental Guideline Regarding Directly-Assigned Facilities

For new facilities or new service over existing third-party transmission provider facilities that meet the definition of Direct Assignment Facilities, metered quantities for Customer deliveries will be adjusted for losses such that BPA is not responsible for losses across such directly assigned facilities. Loss calculations should be similar whether the Customer or the transmission provider owns the directly assigned facilities.

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 offered by the transmission 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 a directly assigned facility (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 service at an existing POD, but must then do so for all similar PODs with that transmission provider. The Customer must take transmission service from BPA at 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.

F. Metering Usage Data Estimation Provision

Pursuant to section 15.1 of the CHWM Contract for the Load Following product, BPA shall apply the Meter Usage Data Estimations procedures posted on the BPA Metering Web site.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. Conservation

1. Conservation Surcharge

The Conservation Surcharge, if 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 applies to the PF-16 (including Slice purchasers), IP-16, and NR-16 rate schedules.

2. Large Project Targeted Adjustment Charge (LPTAC)

The Large Project Targeted Adjustment Charge (LPTAC) rate is based on BPA making funds available for the acquisition of conservation through the Large Project Program (LPP). At any time during the rate period, a customer may submit a project to BPA for consideration of funding through the LPP. Customers will be charged the True Acquisition Cost associated with the funding. All non-participating customers will be held harmless to the costs of LPP funding; all costs accrued to BPA associated with LPP will be funded through contractual arrangements between BPA and participating LPP customers. The charge will be implemented on an individual customer basis.

True Acquisition Cost: The LPTAC will incorporate principal and accrued interest at the BPA Fund rate (BPA's opportunity cost for monies in the BPA Fund) from the time of project funding to the time financing is obtained for the program. After financing, LPP contracts will be charged at a vintage-specific rate over the course of the useful life of the conservation asset acquired, as determined by BPA's capitalization policy for Energy Efficiency investments. The LPTAC will also include the costs for issuance and other costs associated with financing for the conservation project.

Fund Cap: No more than $10 million will be made available during each Rate Period for the LPP.

Eligibility: A Preference customer with a Regional Dialogue contract is eligible to participate. The customer must enter into an LPP agreement that includes the terms and conditions for BPA's acquisition of LPP energy savings from the customer. The customer must submit a completed project proposal, pursuant to the terms in the Implementation Manual, to BPA for consideration. Payment for savings will be made only upon BPA's approval of the project completion report.

B. Cost Contributions

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

1. The approximate cost contribution of different resource categories to each rate schedule is:

Table A
Resource Cost Contribution

Rate Schedule	***Federal Base System***	***Exchange Resources***	***New Resources***
PF	42.36%	57.64%	0%
IP	0%	46.58%	53.42%
NR	0%	46.58%	53.42%
FPS	0%	47.47%	52.53%

2. The cost of resources acquired to meet load growth within the region is estimated to be 43.09 mills/kWh, and the forecast average cost of resources available to BPA under average water conditions is 45.49 mills/kWh.

C. Cost Recovery Adjustment Clause (CRAC)

The CRAC is an upward adjustment to certain rates that can apply to rates during FY 2016 or FY 2017 or both. It applies to these Power rates:

- Non-Slice Customer rate (PF-16)
- PF Melded rate (PF-16)
- Industrial Firm Power rate (IP-16)
- New Resource Firm Power rate (NR-16)

The CRAC also applies to these Transmission rates:

- Reserves-based Ancillary and Control Area Services (ACS-16) rates.

1. Calculations for the Cost Recovery Adjustment Clause

Prior to the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will forecast the end-of-year Accumulated Calibrated Net Revenue (ACNR) for the fiscal year preceding the applicable year. If the forecast ACNR is less than the CRAC Threshold for that applicable year by at least $5 million, the CRAC will trigger, and a rate increase will go into effect beginning on October 1 of the applicable year.

(a) Calculating the Power Calibrated Net Revenue (CNR) and ACNR

The Power CNR is Power net revenue plus the Net Revenue Calibration.

The Net Revenue Calibration is the sum of the effects of a set of differences, one difference calculated for each event not forecast in the BP-16 rate case that affects Power net revenue and Power cashflow (more specifically, changes in Financial Reserves Available for Risk Attributed to Power) differently by more than $5 million. Such events include certain debt management transactions, settlements of contracts, and others. For each event, the impact of the event on Power net revenue will be subtracted from the impact on Power cashflow.

The Power ACNR is Power CNR accumulated since the end of FY 2014. A forecast of ACNR is used to determine whether the CRAC Threshold has been reached, and if so, the required CRAC Amount to be collected. The forecast of ACNR for use in determining the CRAC that will apply to FY 2016 rates will be the forecast of Power Services' Calibrated Net Revenue for FY 2015. The forecast of ACNR for use in determining the CRAC that will apply to FY 2017 rates will be the sum of the actual Power Services' Calibrated Net Revenue for FY 2015 plus the forecast of Power Services' Calibrated Net Revenue for FY 2016.

(b) Calculating the CRAC Amount

The CRAC Amount is based on the Underrun, which is equal to the CRAC Threshold minus forecast ACNR. There are four possibilities:

(1) If the Underrun is less than $5 million, there is no CRAC.

(2) If the Underrun is greater than or equal to $5 million and less than or equal to $100 million, the CRAC Amount is equal to the Underrun.

(3) If the Underrun is greater than $100 million and less than $500 million, the CRAC Amount is equal to $100 million plus one-half of the difference between $100 million and the Underrun.

(4) If the Underrun is greater than or equal to $500 million, the CRAC Amount is equal to $300 million.

NOTE: In cases (2), (3), and (4) above, if an NFB Adjustment increases the CRAC Cap from $300 million to a higher number, the terms will be adjusted. In cases (2) and (3), the "$100 million" figure will be replaced by $100 million plus the difference between the new Cap and $300 million. In cases (3) and (4), the "$500 million" figure will be replaced by $500 million plus twice the difference between the new Cap and $300 million. In case (4), the "$300 million" figure will be replaced by the new Cap.

The CRAC Cap and thresholds are shown in Table B.

Table B
CRAC Annual Thresholds and Caps
(dollars in millions)

ACNR Calculated Near End of Fiscal Year	***CRAC Applied to Fiscal Year***	***CRAC Threshold Measured in ACNR***	***Approx. Threshold as Measured in Power Services Reserves for Risk***	***Maximum CRAC Recovery Amount (Cap)****
2015	2016	($133.5)	$0	$300
2016	2017	($86.5)	$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.

CRAC Threshold is the "trigger point" for invoking a rate increase under the CRAC.

ACNR is Accumulated Calibrated Net Revenue for the generation function, as described in section 1(a).

PS Net Revenue for any given fiscal year is defined as generation function accrued revenue less accrued expenses (in accordance with Generally Accepted Accounting Principles).

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

(c) Calculating the PF/IP/NR CRAC Amount and the ACS CRAC Amount

The PF/IP/NR CRAC Amount is 91.8 percent times the CRAC Amount.

The ACS CRAC Amount is 8.2 percent times the CRAC Amount.

(d) Converting the PF/IP/NR CRAC Amount to the PF/IP/NR CRAC Surcharge

Once the PF/IP/NR CRAC Amount is determined, that amount will be converted to a mills per kilowatthour Surcharge rate added to each of the monthly/diurnal PF Melded, IP, and NR energy rates. The Surcharge rate will be converted to a monthly dollars per one percentage point of Non-Slice TOCA value and added to the Non-Slice Customer Rate.

The PF/IP/NR CRAC Surcharge rate is calculated by dividing the PF/IP/NR CRAC Amount by the most current forecast of kilowatthours of service under the PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable year.

The PF/IP/NR CRAC Surcharge rate is converted to a monthly dollars per one percentage point of Non-Slice TOCA by:

(1) Multiplying the sum of PF System Shaped Loads by the PF/IP/NR CRAC Surcharge rate. The product of this calculation is the annual dollar amount to be collected through the Non-Slice TOCA billing determinant.

(2) Dividing the annual dollar amount to be collected through the Non-Slice TOCA billing determinant by the sum of the Non-Slice TOCAs and dividing the result by 12.

The result of this calculation is a monthly dollars per one percentage point of Non-Slice TOCA rate adjustment.

(e) CRAC Charges for the PF, IP, and NR Rates

For service under the PF Melded, IP, or NR rate: A line item will be added to the bills for the service during the 12 months of the applicable year showing additional charges calculated by multiplying the PF/IP/NR CRAC Surcharge by the applicable kilowatthours of service.

For service under the Non-Slice Customer rate: A line item will be added to the bills for the service during the 12 months of the applicable year showing an additional charge calculated by multiplying the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment by the Non-Slice TOCA.

(f) Converting the ACS CRAC Amount to Charges on Customers' Bills

Once the ACS CRAC Amount is determined, that amount will be passed to Transmission Services. See Transmission GRSP II.G. for details of how those Transmission rates subject to the CRAC will be modified.

(g) Other Rate Adjustments

The Surcharge rate, calculated pursuant to section 1(d), will be subtracted from the Load Shaping Charge True-Up rate to create the CRAC-Adjusted Load Shaping True-Up Rate. See GRSP II.L.

The Surcharge rate, calculated pursuant to section 1(d), will be subtracted from the PF Melded Equivalent Energy Scalar to create the CRAC-Adjusted PF Melded Equivalent Energy Scalar. See GRSP II.W.1(b).

The Surcharge rate, calculated pursuant to section 1(d), will also be added to each of the monthly/diurnal PF Tier 1 Equivalent energy rates. See GRSP II.Q.

2. CRAC Adjustment Timing

Prior to the beginning of each fiscal year in the rate period, the Administrator will calculate the ACNR forecast for the end of that year. If that amount is below the CRAC Threshold, a CRAC rate adjustment will be made for the next fiscal year.

3. CRAC Notification Process

BPA shall follow these notification procedures:

(a) 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 ACNR.

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 ACNR attributable to the generation function.

(b) Notification of CRAC Trigger

BPA shall complete a forecast of end-of-year ACNR in July 2015 for use in calculating the CRAC applicable to rates in FY 2016 and in September 2016 for use in calculating the CRAC applicable to rates in FY 2017. If the forecast value of ACNR is below the CRAC Threshold applicable to the following year by at least $5 million, then BPA shall notify all Customers and rate case parties by late July 2015 of the amount by which BPA intends to adjust rates for FY 2016 due to the CRAC, and by late September 2016 of the amount by which BPA intends to adjust rates for FY 2017.

Notification will be posted on BPA's Web site and will include the forecast of ACNR for the current fiscal year, the audited NR and the NR Calibration for FY 2015 in the case of the CRAC applicable to FY 2017 rates, the CRAC Amount, the PF/IP/NR CRAC Amount, the PF/IP/NR Surcharge, the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment, the CRAC-adjusted Load Shaping True-Up Rate, the CRAC-adjusted PF Melded Equivalent Energy Scalar, the ACS CRAC Amount, and details about how the ACS CRAC Amount has been used to modify Transmission rates for the subsequent fiscal year. The notification shall also describe the data and assumptions relied upon by BPA for all ACNR determinations. BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

Associated with any notification of CRAC calculations as described above, BPA shall conduct a workshop(s) to explain the ACNR calculations, describe the calculation of the CRAC Amount and allocations to various rates, 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 exercise discretion and elect to reduce the CRAC rate adjustment provided (1) 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 2016–2017 rate period in the case of the CRAC applicable to FY 2016 rates; 97.5 percent in the case of the CRAC applicable to FY 2017 rates); and (2) the reduced CRAC will recover in the following year the first $100 million of any use by BPA of the Treasury Facility or liquidity other than Reserves for Risk attributed to Power to pay Power bills plus one-half of any use of the Treasury Facility or liquidity other than Reserves for Risk attributed to Power beyond $100 million, up to a maximum of the CRAC Cap as described above. In the case of the CRAC applicable to the FY 2016 rates, the Administrator may modify the parameters for the CRAC applicable to FY 2017 rates to meet the one-year TPP standard for FY 2017; criterion (2) above must still be met. If the Administrator elects to make such a modification, the Customers shall be informed during the workshop.

If the CRAC applicable to FY 2016 rates triggers, then on or about July 31, 2015, BPA will post to the BPA Web site the final CRAC calculations, including any NFB Adjustment (see GRSP II.N) to the CRAC Cap. If the CRAC applicable to FY 2017 rates triggers, then on or about September 30, 2016, BPA will post to the BPA Web site the final CRAC calculations, including any NFB Adjustment (see GRSP II.N) to the CRAC Cap.

D. Demand Rate Billing Determinant Adjustments

BPA may adjust Customers' bills after the fact for changes to demand charge billing determinants, as described below.

1. Extreme Load Shift Demand Billing Determinant Adjustment

(a) Calculating the Billing Determinant

If a Customer's monthly CDQ-adjusted HLH load factor (aHLH divided by the quantity (i) Tier 1 CSP minus (ii) CDQ minus (iii) SuperPeak) is less than 55 percent, BPA may recompute a Customer's demand billing determinant for the month. The month shall first be separated into two or more partial-month periods using the extreme load shift events that occur during the month as demarcations for the periods. For each partial-month period, a separate demand value shall be calculated using the same arithmetic method used to compute the Customer's demand billing determinant for the full month, but such calculation shall use only the peak and energy consumed during each partial-month period. If BPA agrees to an adjustment, the largest of the partial-month demand values among the partial-month periods shall be used as the Customer's demand billing determinant for the entire month.

(b) Notification Requirement

The Customer shall be responsible for notifying BPA in the event it believes it may qualify for an extreme load shift demand billing determinant recalculation. BPA shall not be responsible for demand billing determinant recalculation without Customer notification. BPA will not consider a Customer request to recalculate a demand billing determinant when such request occurs more than 90 days after the Customer's power bill is produced and communicated to the Customer.

2. Recovery Peak Demand Billing Determinant Adjustment

(a) Calculating the Billing Determinant

The demand CSP may be reduced by the kilowatt difference between the CSP resulting from a Recovery Peak and the next highest HLH peak during the month that is not a Recovery Peak.

Recovery Peak shall mean an extraordinary CSP measured in a Customer's load following return to service from an outage. A Recovery Peak for which BPA would consider a Recovery Peak Demand Billing Determinant Adjustment must have all three of the following characteristics:

(1) the CSP occurred during one of the two (2) hours immediately following restoration of service after an outage due to an Uncontrollable Force, provided that the outage lasted for two hours or more;

(2) the outage reduced the utility's Total Retail Load (TRL) by 25 percent or more; and

(3) the demand billing determinant resulting from such a CSP is ten percent or more of those CSP kilowatts.

In determining the 25 percent threshold, the TRL reduction is computed by comparing the TRL measured during any hour of the outage to the TRL measured in the hour ended immediately prior to the hour in which the outage began. BPA may consider evidence that an observed CSP is not extraordinary. Such evidence may include that substantial restoration of service occurred more than two hours prior to the potential Recovery Peak hour, the hourly load patterns before and after the outage, and loads of similarly situated Customers that did not experience a simultaneous outage due to Uncontrollable Force.

(b) Notification Requirement

The Customer shall be responsible for notifying BPA in the event it believes it may qualify for a demand billing determinant recalculation. BPA shall not be responsible for demand billing determinant recalculation without Customer notification. BPA shall not consider a Customer request to recalculate a demand billing determinant when such request occurs more than 90 days after the Customer's power bill is produced and communicated to the Customer.

E. Dividend Distribution Clause (DDC)

The DDC is a downward adjustment to certain rates; it can apply to rates during FY 2016 or FY 2017 or both. It applies to these Power rates:

- Non-Slice Customer rate (PF-16)
- PF Melded rate (PF-16)
- Industrial Firm Power rate (IP-16)
- New Resource Firm Power rate (NR-16)

The DDC also applies to these Transmission rates:

- Reserves-based Ancillary and Control Area Services (ACS-16) rates.

1. Calculations for the Dividend Distribution Clause

Prior to the beginning of each fiscal year of the rate period (that is, each "applicable year"), BPA will forecast the end-of-year Accumulated Calibrated Net Revenue (ACNR) for the fiscal year preceding the applicable year. If the forecast ACNR is greater than the DDC Threshold for that applicable year by at least $5 million, the DDC will trigger, and a rate decrease will go into effect beginning on October 1 of the applicable year.

(a) Calculating the DDC Amount

The DDC Amount will be equal to either the forecast ACNR less the DDC Threshold or $1,000 million, whichever is smaller.

Table C
DDC Annual Thresholds and Cap
(dollars in millions)

ACNR Calculated Near End of Fiscal Year	***DDC Applied to Fiscal Year***	***DDC Threshold Measured in ACNR***	***Approx. Threshold as Measured in Power Services Reserves for Risk***	***Maximum DDC Distribution Amount (Cap)***
2015	2016	$616.5	$750	$1,000
2016	2017	$663.5	$750	$1,000

Where:

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

DDC Threshold is the "trigger point" for invoking a rate decrease under the DDC.

ACNR is Accumulated Calibrated Net Revenue for the generation function, as defined in GRSP II.C.1.(a) above.

PS Net Revenue for any given fiscal year is defined as generation function accrued revenue less accrued expenses (in accordance with Generally Accepted Accounting Principles).

Maximum DDC Recovery Amount (Cap) is the maximum annual amount that is allowed to be distributed through the DDC.

(b) Calculating the PF/IP/NR DDC Amount and the ACS DDC Amount

The PF/IP/NR DDC Amount is 91.8 percent times the DDC Amount.

The ACS DDC Amount is 8.2 percent times the DDC Amount.

(c) Converting the PF/IP/NR DDC Amount to the PF/IP/NR DDC Credit

Once the PF/IP/NR DDC Amount is determined, that amount will be converted to a mills per kilowatthour PF/IP/NR DDC Credit rate and subtracted from each of the monthly/diurnal PF Melded, IP, and NR energy rates. The mills per kilowatthour PF/IP/NR DDC Credit will be converted to a monthly dollars per one percentage point of Non-Slice TOCA value and subtracted from the Non-Slice Customer Rate.

The PF/IP/NR DDC Credit rate is calculated by dividing the PF/IP/NR DDC Amount by the most current forecast of kilowatthours of service under the PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable year.

The PF/IP/NR DDC Credit rate is converted to a monthly dollars per one percentage point of Non-Slice TOCA by:

(1) Multiplying the sum of PF System Shaped Loads by the PF/IP/NR DDC Credit rate. The product of this calculation is the annual dollar amount to be distributed through the Non-Slice TOCA billing determinant.

(2) Dividing the annual dollar amount to be distributed through the Non-Slice TOCA billing determinant by the sum of the Non-Slice TOCAs and dividing the result by 12.

The result of this calculation is a monthly dollars per one percentage point of Non-Slice TOCA rate adjustment.

(d) DDC Credits for the PF, IP, and NR Rates

For service under PF Melded, IP, or NR rates: A line item will be added to the bills for the service during the 12 months of the applicable year showing credits calculated by multiplying the PF/IP/NR DDC Credit by the applicable kilowatthours of service.

For service under the PF Non-Slice Customer rate: A line item will be added to the bills for the service during the 12 months of the applicable year showing a credit calculated by multiplying the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment by the Non-Slice TOCA.

(e) Converting the ACS DDC Amount to Charges on Customers' Bills

Once the ACS DDC Amount is determined, that amount will be passed to Transmission Services. See Transmission GRSP II.G for details of how those Transmission rates subject to the DDC will be modified.

(f) Other Rate Adjustments

The Credit rate, calculated pursuant to section 1(c), will be added to the Load Shaping True-Up Rate to create the DDC-Adjusted Load Shaping True-Up Rate. See GRSP II.L.

The Credit rate, calculated pursuant to section 1(c), will be added to the PFp Melded Equivalent Energy Scalar to create the DDC-Adjusted PF Melded Equivalent Energy Scalar. See GRSP II.W.1(b).

The Credit rate, calculated pursuant to section 1(c), will also be subtracted from each of the monthly/diurnal PF Tier 1 Equivalent energy rates. See GRSP II.Q.

2. DDC Adjustment Timing

Prior to the beginning of each fiscal year in the rate period, the Administrator will calculate the ACNR forecast for the end of that year; if that amount is above the DDC Threshold, a DDC rate adjustment will be made 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 ACNR.

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 ACNR attributable to the generation function.

(2) Notification of DDC Trigger

BPA shall complete a forecast of end-of-year ACNR in July 2015 for use in calculating the DDC applicable to rates in FY 2016, and in September 2016 for use in calculating the DDC applicable to rates in FY 2017. If the forecast value of

ACNR is above the DDC Threshold applicable to the following year by at least $5 million, then BPA shall notify all Customers and rate case parties by late July 2015 of the amount by which BPA intends to adjust rates for FY 2016 due to the DDC, and by late September 2016 of the amount by which BPA intends to adjust rates for FY 2017.

Notification will be posted on BPA's Web site and will include the forecast of ACNR for the current fiscal year, the audited NR and the NR Calibration for FY 2015 in the case of the DDC applicable to FY 2017 rates, the DDC Amount, the PF/IP/NR DDC Amount, the PF/IP/NR Surcharge, the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment, the DDC-adjusted Load Shaping True-Up Rate, the DDC-adjusted PF Melded Equivalent Energy Scalar, the ACS DDC Amount, and details about how the ACS DDC Amount has been used to modify Transmission rates for the subsequent fiscal year. The notification shall also describe the data and assumptions relied upon by BPA for all ACNR determinations. BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

Associated with any notification of DDC calculations as described above, BPA shall conduct a workshop(s) to explain the ACNR calculations, describe the calculation of the DDC Amount and allocations to various rates, and demonstrate that the DDC has been implemented in accordance with these GRSPs. The workshop(s) will provide an opportunity for public comment.

If the DDC applicable to FY 2016 rates triggers, then on or about July 31, 2015, BPA will post to the BPA Web site the final DDC calculations. If the DDC applicable to FY 2017 rates triggers, then on or about September 30, 2016, BPA will post to the BPA Web site the final DDC calculations.

F. DSI Reserves

DSI Value of Reserves Adjustment. Pursuant to section 7(c)(3) of the Northwest Power Act (16 U.S.C. § 839e(c)(3)), a DSI Customer's wholesale power bill will be adjusted to reflect the value of the Minimum DSI Operating Reserve – Supplemental. The DSI Operating Reserve – Supplemental is a contractual right for BPA to interrupt DSI load being served with Industrial Firm Power in a megawatt amount equal to 10 percent of the amount of power scheduled for delivery at the time the interruption request occurs. The Minimum DSI Operating Reserve – Supplemental provided by a DSI Customer must be consistent with North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) standards and criteria, including the following:

1. The interruptible load must be off-line or the increased generation must be on-line within 10 minutes after a call from BPA.

2. In the event of a system disturbance, the interruptible load or increased generation must be accessible in advance of any need for BPA to request reserves from other Northwest Power Pool members.
3. The interruptible load must be available to be off-line for up to 105 minutes, or increased generation must be available to be on-line for up to 105 minutes.
4. There are no limitations on the number of times or aggregate minutes the Minimum DSI Operating Reserve – Supplemental may be utilized.

Optional Reserves. BPA is not obligated to purchase any DSI Reserves(s) beyond the Minimum DSI Operating Reserve – Supplemental. However, BPA's contracts with DSI Customers contain a contingent right to purchase additional reserves to the extent they are needed for operational purposes and can be made available by the Customer. These contract provisions are designed to provide flexibility that will allow BPA to negotiate company-specific interruption rights, with the price for such reserves based on the characteristics of the DSI Reserve(s) provided. To ensure that any such purchases by BPA are cost-effective, the maximum amount to be paid by Power Services is capped at $7.62 per kW per month.

The availability of optional DSI Reserve(s) purchased by BPA must be consistent with NERC, WECC, and NWPP standards and criteria specific to balancing authority area Operating Reserve Requirements, including the following characteristics:

1. The interruptible load must be off-line or the increased generation on-line within the period specified for the applicable DSI Reserve purchased.

2. The interruptible load or increased generation must be accessible in advance of any need to request reserves from other Northwest Power Pool members.

In addition to these to these two characteristics, the issues identified below will guide consideration of when BPA may pay the maximum value for DSI Reserves:

1. The degree to which BPA has discretion with respect to when and how to use the reserves and to determine what resources to call on in the event of system disturbance or for some other purpose specified in any negotiated agreement for optional reserves.

2. Duration of time the interruptible load is available to be off-line or increased generation is available to be on-line.

G. NR Services for New Large Single Loads (NLSLs)

NR Services for NLSLs are applicable to Load Following Customers serving NLSLs with non-Federal resources.

1. NR Energy Shaping Service

1.1 NR Energy Shaping Service Energy Charge

The energy component of the NR Energy Shaping Service either credits or debits the Customer for the difference between energy amounts provided by the Customer's non-Federal resources serving NLSLs and the measured load of their NLSLs.

The NR ESS energy charge can be either positive or negative and is determined through a two-step process. The first step determines the applicable rate treatment, A or B. The second step applies the rate treatment determined in the first step.

Step 1:
Determine if the Customer received energy from BPA or provided energy to BPA on a net monthly basis, calculated as the measured load of the Customer's NLSLs in the billing month minus the energy amounts provided by the Customer's resources to serve their NLSLs during the same billing month. If this result is greater than zero, energy was purchased from BPA, and rate treatment A applies. If this result is zero or negative, rate treatment B applies.

Step 2:
ESS Energy Rate Treatment A.
Calculate two energy billing determinants for each month, one for HLH and one for LLH. Each monthly energy billing determinant is equal to (1) the total measured load of the Customer's NLSL(s) receiving this service during the monthly/diurnal period minus (2) the energy amounts provided by the Customer to serve those NLSLs during that same monthly/diurnal period. The billing determinant for either period can be negative. These billing determinants are multiplied by the applicable monthly/diurnal NR energy rates to calculate the energy charge (or credit). Section 2.1.1 of the NR rate schedule includes 24 Energy rates (two diurnal periods—HLH and LLH—for each of 12 months).

ESS Energy Rate Treatment B.
Calculate daily diurnal billing determinants for the month, resulting in two billing determinants for each day with both HLH and LLH periods and one billing determinant for each day with only a LLH period. Each energy billing determinant is equal to (1) the total measured load of the Customer's NLSL(s) receiving this service during that daily/diurnal period minus (2) the energy amounts provided by the Customer to those NLSLs during that same daily/diurnal period. The billing determinant for any period can be negative. These billing determinants are multiplied by the applicable Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index (or its replacement) for the same daily/diurnal period to calculate each daily/diurnal period energy charge. If a Mid-C price for any period is less than zero, the applicable rate for that period will be zero.

The monthly sum of such daily/diurnal energy charges may be adjusted as follows:

- Threshold 1: No adjustment is made if the absolute value of the monthly sum of the daily HLH plus LLH billing determinants is less than or equal to (i) 1.5 percent of the total monthly measured load of the NLSLs receiving this service, or (ii) 1,488 MWh.

- Threshold 2: If Threshold 1 is exceeded, Threshold 2 will apply if the absolute value of the monthly sum of the daily HLH plus LLH billing determinants is less than or equal to (i) 7.5 percent of the total monthly measured load of the NLSLs receiving this service, or (ii) 3,720 MWh. If Threshold 2 applies, the monthly sum of the daily/diurnal energy charges will be multiplied by 94 percent if the monthly sum is negative (money owed to the Customer) or multiplied by 106 percent if the monthly sum is positive (money owed to BPA).

- Threshold 3: If both Threshold 1 and 2 are exceeded, Threshold 3 applies. When applying Threshold 3, the monthly sum of the daily HLH plus LLH energy charges is multiplied by 84 percent if the monthly sum is negative (money owed to the Customer), or multiplied by 116 percent if the monthly sum is positive (money owed to BPA).

1.2 NR Energy Shaping Service Capacity Charge

The billing determinant for the NR ESS Capacity Charge is the amount of capacity the Customer requests from BPA for standing ready to serve its NLSLs. The Customer must have established monthly capacity amounts for the FY 2016-2017 rate period prior to February 1, 2015. However, at least 30 days prior to any month, the Customer may notify BPA of a change to the amount of capacity it is requesting BPA to stand ready to serve its NLSLs for that month.

The billing determinant is multiplied by the applicable monthly NR demand rate (NR Rate Schedule section 2.2.1) to calculate the monthly NR ESS Capacity Charge.

A monthly check will be performed to verify the Customer’s actual capacity use did not exceed the monthly amount of capacity it requested BPA to provide. The actual capacity used is equal to (1) the largest hourly energy amount provided by BPA during the HLH of the month through the NR ESS minus (2) the greater of (i) the average HLH energy provided by BPA under Rate Treatment A, in that same month, or (ii) zero. The Unauthorized Increase (UAI) Charge for demand will apply to the actual capacity used in excess of the monthly amounts of capacity included in the Customer’s request to BPA.

2. NR Resource Flattening Service

The NR Resource Flattening Service (NRFS) is applicable to Load Following Customers that apply the generation output of a non-dispatchable Specified Resource to serve an NLSL.

2.1 NR Resource Flattening Service Energy Charge

The NRFS energy charge is the product of multiplying the NRFS energy rate by the NRFS energy billing determinant for each month.

2.2 NR Resource Flattening Service Energy Rate

NRFS is a unique energy rate developed for each resource to which NRFS is applied. For each monthly/diurnal period in a year, the sum of the hourly planned generation in excess of average monthly/diurnal planned generation amounts is multiplied by 25 percent (to reflect the energy lost when using a pumped storage hydroelectric unit to perform the energy storage). The result is multiplied by the applicable monthly/diurnal Resource Shaping rate. The monthly/diurnal results are summed for the year and divided by the total planned energy amounts to calculate the NRFS Energy rate.

2.3 NR Resource Flattening Service Energy Billing Determinant

The NRFS energy billing determinant is the total actual generation for the particular resource during the billing month. The actual generation amounts will be either the resource meter readings, or the resource transmission schedules if the resource requires an e-Tag.

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

The Flexible NR rate option will be offered at BPA's discretion to a Customer that makes a contractual commitment to purchase under this option. The rates and billing determinants under this option shall be specified by BPA at the time the Administrator offers to make power available to a Customer under this option. The Customer under the Flexible NR rate option shall purchase the same set of power products and services that it would otherwise purchase under the NR-16 rate schedule. The flexible rates and billing determinants will be mutually agreed to by BPA and the Customer, subject to satisfying the following conditions:

- Equivalent NPV Revenue: Forecast revenue from a Customer 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 sections 2 and 3 of the NR-16 rate schedule 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 rates specified in sections 2 and 3 of the NR-16 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the NR-16 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 NR Rate program by purchasing under the Flexible NR Rate Option shall survive and be fully enforceable until such time as they are fully satisfied.

I. Flexible Priority Firm Power (PF) Rate Option

The Flexible PF rate option will be offered at BPA's discretion to a Customer that makes a contractual commitment to purchase under this option. The rates and billing determinants under this option shall be specified by BPA at the time the Administrator offers to make power available to a Customer under this option. The Customer under the Flexible PF rate option shall purchase the same set of power products and services that it would otherwise purchase under the PF-16 rate schedule. The flexible rates and billing determinants will be mutually agreed to by BPA and the Customer, subject to satisfying the following conditions:

- Equivalent NPV Revenue: Forecast revenue from a Customer 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 sections 2, 3, 4, and 5 of the PF-16 rate schedule 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 rates specified in sections 2, 3, 4, and 5 of the PF-16 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the PF-16 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.

J. General Transfer Agreement Service Charges

The General Transfer Agreement Service applies to BPA Power Service Customers that are served under General Transfer Agreements (GTAs) or other non-Federal transmission service agreements.

1. GTA Delivery Charge

The GTA Delivery Charge shall apply to Power Services Customers that purchase Federal power that is delivered over non-Federal low-voltage facilities. Low-voltage facilities are generally facilities operated below 34.5 kV.

(a) GTA Delivery Rate

	Rate in $/kW
All months	0.94

(b) GTA Delivery Billing Determinant

The monthly billing determinant for the GTA Delivery rate shall be the total load on the hour of the Total Customer System Peak minus behind-the-meter dedicated resources or resources contractually committed to serve Customer load at the low-voltage Points of Delivery provided for in GTA and other non-Federal transmission service arrangements.

2. Transfer Service Operating Reserve Charge

The Transfer Service Operating Reserve Charge shall apply to Public Customers that meet the following criteria: (1) BPA serves the Customer under a GTA or other non-Federal transmission service agreements; and (2) the Customer is not paying BPA Transmission Services for operating reserve for the Customer's load pursuant to WECC standard BAL-002-WECC-2.

(a) Transfer Services Operating Reserve Rate

(1) The rate for the Transfer Service Spinning Operating Reserve Charge shall be equal to the ACS-16 Operating Reserve – Spinning Reserve Service rate.

(2) The rate for the Transfer Service Supplemental Operating Reserve Charge shall be equal to the ACS-16 Operating Reserve – Supplemental Reserve Service rate.

(b) Transfer Services Operating Reserves Billing Determinant

(1) The monthly billing determinant for the Transfer Service Spinning Operating Reserve Charge shall be the metered load of the Customer served by transfer (non-BPA Balancing Authority Area load).

(2) The monthly billing determinant for the Transfer Service Supplemental Operating Reserve Charge shall be the metered load of the Customer served by transfer (non-BPA Balancing Authority Area load).

3. Transfer Services WECC Charge

The Transfer Services WECC Charge shall apply to Public Customers with load outside the BPA Balancing Authority Area.

(a) Transfer Services WECC Rate

	Rate in mills/kWh
All months	0.0297

(b) Transfer Services WECC Billing Determinant

The monthly billing determinant for the Transfer Services WECC Charge shall be the metered load at points of delivery of the Public Customer served by transfer (non-BPA Balancing Authority Area load).

4. Transfer Services Peak Charge

The Transfer Services Peak Charge shall apply to Public Customers with load outside the BPA Balancing Authority Area.

If the Peak Reliability Coordinator does not assess any charges to BPA for Transfer Services customer loads outside the BPA Balancing Authority Area, Public Customers will not be assessed the Transfer Services Peak Charge.

(a) Transfer Services Peak Rate

	Rate in mills/kWh
All months	0.0392

(b) Transfer Services Peak Billing Determinant

The monthly billing determinant for the Transfer Services WECC Charge shall be the metered load at points of delivery of the Power Services Customer served by transfer (non-BPA Balancing Authority Area load).

K. Irrigation Rate Discount

1. Discount for Eligible Customers

Section 3 of Exhibit D of the CHWM Contracts describes Irrigation Rate Mitigation (IRM), and section 10.3 of the Tiered Rate Methodology describes an Irrigation Rate Mitigation Product (IRMP). Both the IRM and IRMP are implemented through the Irrigation Rate Discount (IRD) set forth in this provision.

In May, June, July, August, and September, an eligible Customer shall have the Irrigation Rate Discount of 11.77 mills/kWh applied to the lesser of the amount of energy purchased at Tier 1 rates in the month or the irrigation load amounts listed in Exhibit D of its CHWM Contract.

The eligibility amounts for the Irrigation Rate Discount are set forth in section 3.1 of Exhibit D of the CHWM Contracts and are subject to the True-Up process referenced in section 3.2 and described more fully below.

For a Load Following or Block Customer, the energy purchased at Tier 1 rates will be equal to its Actual Monthly/Diurnal Tier 1 Load used to calculate its Load Shaping billing determinant. For a Slice/Block Customer, the energy purchased at Tier 1 rates will be equal to the sum of the Customer's monthly Block purchase at Tier 1 rates plus the Customer's Slice percentage multiplied by the monthly/diurnal RHWM Tier 1 System Capability.

The Irrigation Rate Discount for a Joint Operating Entity (JOE) will be calculated based on individual utility members' loads and billed to the JOE and designated for each eligible utility.

BPA requires a participating Customer to implement cost-effective conservation measures on eligible irrigation systems in its service territories. The Customer may use its Energy Efficiency Incentive fund for this purpose.

2. Metering Requirements

The Customer is required to read irrigation meters at the beginning of May and after the end of the Irrigation Rate Discount season (September 30). The Customer shall provide to BPA monthly metered irrigation load information for the months of May through September in a form that is acceptable to BPA no later than October 31 of each year to ensure a timely True-Up calculation.

3. Irrigation Rate Discount True-Up and Reimbursement

There will be an assessment of the Irrigation Rate Discount each November to ensure the Customer served the full amount of irrigation load for which it received an Irrigation Rate Discount. The actual metered irrigation kilowatthour amounts submitted by the Customer each year will be increased by 7 percent to account for losses (measured irrigation load) before they are compared to the billed irrigation load amounts.

If the sum of a Customer's May through September measured irrigation load is less than the sum of the May through September billed irrigation load amounts, a True-Up calculation is required. However, if the sum of a Customer's May through September measured irrigation load is greater than or equal to the sum of the May through September billed irrigation load amounts, a True-Up calculation is not applicable.

The True-Up is calculated as follows: The measured irrigation load for the May through September period will be subtracted from the sum of the May through September billed irrigation load amounts. The result, if positive, will be multiplied by the Irrigation Rate Discount to determine the True-Up reimbursement. The True-Up reimbursement shall appear as a charge on a subsequent monthly power bill.

L. Load Shaping Charge True-Up Adjustment

The Load Shaping Charge True-Up Adjustment is applicable to Customers purchasing the Load Following product in specific circumstances. The Adjustment shall be determined following each fiscal year of the rate period and shall appear on the Customers' power bills.

1. Load Shaping Charge True-Up Rate

FY	***Rate in mills/kWh***
2016	–8.85
2017	–8.85

2. Load Shaping Charge True-Up Billing Determinants

(a) Annual Deviation

The Annual Deviation for each Customer determines whether the Customer may be eligible for a True-Up charge or credit.

Annual Deviation = Actual Annual Tier 1 Load (measured) *minus* TOCA Load (calculated)

TOCA Load is the annual amount of energy that is used to calculate the Customer's TOCA. If the Customer's TOCA is modified pursuant to the TOCA Adjustment, GRSP II.Y, TOCA Load will reflect the Adjusted TOCA. If Annual Deviation is zero, there may be no True-Up; see Special Implementation Provision, section 3 below.

(b) True-Up Credit

If Annual Deviation is positive, the Customer is eligible for a True-Up credit if Above-Forecast Amount is positive (greater than zero).

Above-Forecast Amount = RHWM (calculated) *minus* TOCA Load (calculated)

If Above-Forecast Amount is positive, the True-Up Credit billing determinant equals negative one (-1) multiplied by the lesser of:

(1) Annual Deviation, or

(2) Above-Forecast Amount.

There is no True-Up if Above-Forecast Amount equals zero (0).

(c) True-Up Charge

If Annual Deviation is negative, the Customer may be subject to a True-Up charge. If Above-RHWM Load is less than the absolute value of the Annual Deviation, the Customer is subject to a True-Up charge.

True-Up Charge Billing Determinant	=	Absolute value of the Annual Deviation *minus* Above-RHWM Load

The True-Up Charge billing determinant cannot be less than zero.

3. Special Implementation Provision

Special implementation provisions apply if two conditions are met:

(a) the Customer has Above-RHWM load

and

(b) the Customer has an Above-Forecast Amount greater than zero.

If both these conditions are met, the Customer may be eligible for an additional Load Shaping True-Up credit.

If the Annual Deviation is negative or zero and the absolute value of the Annual Deviation is less than the Customer's Above-RHWM load, then the Special True-Up Credit billing determinant is negative one (-1) multiplied by the least of (i) the Customer's Above-RHWM load; (ii) the Above-RHWM load minus the absolute value of the Annual Deviation; or (iii) the Above-Forecast Amount.

If the Annual Deviation is positive and the Annual Deviation amount is less than the Above-Forecast amount, then the Special True-Up Credit billing determinant is negative one (-1) multiplied by the lesser of (i) the Customer's Above-RHWM load; or (ii) the Above-Forecast amount minus the Annual Deviation.

4. Load Shaping Charge True-Up Adjustment

The Load Shaping Charge True-Up Adjustment is equal to the Load Shaping Charge True-Up Rate multiplied by the sum of (i) the True-Up Credit billing determinant; (ii) the True-Up Charge billing determinant; and (iii) the Special True-Up Credit billing determinant.

The final Load Shaping Charge True-Up Adjustment for each Customer shall be applied as either a one-month credit (if the adjustment is negative) or a three-month charge (if the adjustment is positive) spread equally across the three months following the month the final Load Shaping Charge True-Up Adjustment is determined by BPA. Load Shaping

Customers have the option to pay the entire charge in one month. There shall be no interest component applied to the Load Shaping Charge True-Up payment schedule.

M. Low Density Discount (LDD)

1. Application and Definitions

For eligible Customers, as defined in section 2 below, a Low Density Discount (LDD) shall be applied each billing month to the PF-16 Composite Customer charge, PF-16 Non-Slice Customer charge, PF-16 Load Shaping charge, PF-16 Load Shaping Charge True-Up Adjustment, and PF-16 demand charge. The LDD also applies to eligible Customers under the PF-16 Melded rate schedule and the NR-16 rate schedule. The LDD shall be applied to only those charges listed in this GRSP II.M.

For Load Following and Block purchases, the applicable discount percentage will apply to all charges for purchases by the Customer under the Tier 1 rates (Composite Customer charge, Non-Slice Customer charge, Load Shaping charge, Load Shaping Charge True-Up Adjustment, and demand charge). The applicable discount percentage will be adjusted for Above-High Water Mark load, as described in section 6 below.

For Slice/Block purchases, an LDD dollar benefit will be calculated by BPA as though it was a Load Following purchase. BPA will use the Customer's previous fiscal year's load data to calculate an annual LDD dollar benefit amount. This amount will be divided by 12 to derive a monthly LDD dollar credit, which will be applied to the Customer's monthly power bills over the next 12 months. There will be no separate Slice and Block LDD benefits calculated. The applicable discount percentage will be adjusted for Above-High Water Mark load, as described in section 6 below.

The eligible and applicable discount percentages 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.

The calculation of the ratios below shall be based on calendar year data the Customer provides from its annual financial and operating reports (*e.g.*, Rural Utilities Service Financial and Operating Report - Electrical Distribution, National Rural Utilities Cooperative Finance Corporation Financial and Statistical Report (CFC Form 7), audited financial report, or Annual Report). The provided annual financial and operating reports shall include the Customer's Total Retail Load, depreciated electric plant, number of consumers, pole miles of distribution lines, total kilowatthours sold, and total electric retail sales revenue. The annual financial and operating report is to be enclosed with the Customer's calendar year data if not previously submitted to BPA. The Customer shall certify that the data submitted is true and correct.

Load acquired by a Customer as a direct result of retail access rights established by Federal, state, or local legislation, that would not otherwise have been acquired absent such legislation, is not eligible to receive the benefits provided by the LDD. The

Customer shall certify that the data submitted does not include such load. The Customer shall not pass the benefits of the LDD to such acquired consumers.

In calculating the ratios below, BPA shall compile the data submitted by the Customer based on the Customer's entire electric utility system in the Pacific Northwest (PNW). For Customers with service territories that include any areas outside the PNW, BPA shall compile data submitted by the Customer separately on the Customer's system in the PNW and on the Customer's entire electric system, including areas outside the PNW. BPA shall apply the eligibility criteria and discount percentages to the Customer's system within the PNW and, where applicable, also to its entire system inside and outside the PNW. The Customer's eligibility for the LDD shall 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 Customer with a small amount of its system outside the PNW. Results of the calculations shall not be rounded.

If a Customer does not provide BPA with the requisite information and reports by June 30 of each year for BPA to calculate the K/I and C/M ratios (see below), the Customer shall be ineligible for the LDD effective the following October 1. The Customer may reapply for the LDD in any subsequent year.

If a Customer's data and reports are submitted prior to the June 30 deadline, and a revision is necessary, the Customer must submit the revised data within 12 months of the original submission date to be considered for an adjustment.

(a) The Kilowatthour/Investment Ratio

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

(b) The Consumers/Pole Miles Ratio

The Consumers/Pole Miles (C/M) ratio is calculated annually based on the data the Customer supplies by June 30 of each calendar year. The C/M ratio is calculated by dividing the Customer's number of consumers within the distribution system at the end of the previous calendar year, as defined below, by the number of pole miles of distribution lines at the end of the previous calendar year.

"Consumers" means the number of consumers, by classification, having a current service connection in December of each year. Residential consumers (seasonal and non-seasonal) are counted on the basis of the number of residences served. If one meter serves two residences, then two consumers are counted. If a water heater is metered separately from other appliances on the same premises, the water heater load will not count as a separate consumer.

Security or safety lights billed to a residential consumer will not be counted as an additional consumer.

Additional meters used for net metering consumers will not be counted as an additional consumer.

Seasonal consumers expected to resume service during the next seasonal period will be counted during off-season periods as well.

A residence and commercial establishment on the same premises receiving service through the same meter and being billed under the same rate schedule would be classified as one consumer based on the rate schedule. If the same rate schedule applies to both the residential and the commercial class, the consumer should be classified according to the principal use.

Consumers for Public Street and Highway Lighting shall be counted by the number of billings, regardless of the number of lights per billing.

Pole miles of distribution lines are defined as lines that deliver electric energy from a substation or metering point at a voltage of 34.5 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.)

2. Eligibility Criteria

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

(a) The Customer must serve as an electric utility offering power for resale to retail consumers.

(b) The Customer must agree to pass the benefits of the discount through to its eligible consumers within the region served by BPA.

(c) The Customer'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, which is 41.00 mills/kWh for FY 2016 and FY 2017.

(d) The Customer's K/I ratio must be less than 100.

(e) The Customer's C/M ratio must be less than 12.

Each year BPA shall determine whether a Customer is eligible for a discount. Such determination shall not be dependent on whether the Customer was determined to be eligible in the previous year.

3. Determination of Eligible Discount percentage

For each Customer, an eligible discount percentage shall be determined using Table D below. The eligible discount percentage shall be the sum of the two potential discount percentages for which the Customer qualifies, based on Table D. The total eligible discount percentage shall not exceed 7 percent and may be adjusted pursuant to sections 4, 5, and 6 below.

Table D
LDD Eligible Discount percentage

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

4. LDD Phase-In Adjustment

If the Customer satisfies the eligibility criteria in section 2(a) through (e) above and the calculated eligible discount percentage differs from the existing eligible discount percentage by more than one-half of 1 percentage point, the applicable eligible discount percentage shall be one of the following amounts:

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

(b) the existing eligible discount percentage minus a maximum of one-half percent if the calculated eligible discount percentage is less than the existing discount.

The foregoing formula shall be applied each October 1 until the existing eligible discount percentage is equal to the calculated eligible discount percentage.

The Customer is not eligible to receive any discount, effective each October, if the Customer fails to meet the eligibility criteria in sections 2(a) through (e) above. If the Customer is eligible to receive a discount in a year following a year in which the Customer was not eligible to receive the discount, then the one-half percent phase-in adjustment described above shall apply to the most recent eligible discount.

5. Additional Adjustment for Very Low Densities

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

6. Applicable Discount for Customers with Above-RHWM Load

A discount is not provided for the costs of power used to serve the Customer's Above-RHWM load; however, the LDD benefit will be adjusted to be approximately the same as if the Above-RHWM load was included. This adjustment modifies the Customer's eligible discount percentage. The formula used to calculate the applicable discount percentage for eligible purchases on the Customer's power bill during the rate period is:

$$applicableLDD = eligibleLDD \times \max\left(\frac{adjTRL}{RHWM}, 1.0\right)$$

Where:

applicableLDD = the discount percentage to be applied to the Tier 1 charges on a Customer's bill

eligibleLDD = the Customer's eligible discount percentage as computed according to sections 2 through 5 above

adjTRL = the Customer's Total Retail Load less output of Existing Resources and NLSLs, as determined in the RHWM Process for the applicable fiscal year

RHWM = the Customer's Rate Period High Water Mark for the applicable fiscal year

Any Customer with *adjTRL* less than its *RHWM* will have its applicable discount percentage set equal to its eligible discount percentage.

7. Treatment for Joint Operating Entity

The LDD benefit to a JOE will be equivalent to the sum of LDD benefits for all eligible individual members of the JOE. Except for LDD benefits for Tier 1 demand, the LDD benefits for the JOE will be based on each such individual utility member's applicable discount percentage applied to all charges for purchases by the individual utility member under the Tier 1 rates according to section 1 above. The monthly LDD benefit for demand for a JOE is calculated as follows:

(a) Each individual utility member's demand billing determinant is calculated as if such member were not a member of a JOE.

(b) The demand billing determinants for all individual utility members are summed.

(c) The individual utility members' calculated demand billing determinants are scaled (up or down) so that the sum of all individual utility members' calculated demand billing determinants equals the JOE's demand billing determinant.

(d) The demand LDD benefit attributable to each eligible individual member of the JOE is equal to the member's scaled demand billing determinant multiplied by the member's applicable discount percentage and the applicable monthly Tier 1 demand charge.

(e) The demand LDD benefits of the eligible individual members of the JOE are summed to yield the demand LDD benefit to the JOE.

N. 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 Net Revenue. The first mechanism, the NFB Adjustment, would increase the CRAC Cap applicable to the fiscal year(s) following the fiscal year in which an NFB Trigger Event resulting in Financial Effects occurs. The second mechanism, the Emergency NFB Surcharge, would increase rates 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 section 3 below).

1. Definitions

(a) An NFB Trigger Event is one of the following 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 (also known as NOAA Fisheries Service) or the U.S. Fish and Wildlife 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, 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, Litigation.

(5) Actions or measures ultimately required under the 2014 Supplemental FCRPS BiOp that differ from the 2014 Supplemental FCRPS BiOp implementation forecast in the rate case.

(b) Financial Effects of a Trigger Event are net reductions in estimated Power Services' Net Revenue 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, USACE and Reclamation O&M expenses, direct program expenses of the USFWS, 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 by any previous Trigger Events. These effects are the total effects on the BPA System, excluding the operational or expense effects borne by Slice Customers.

(c) The Agency Within-Year TPP is the probability that BPA (including both Power Services and Transmission Services) 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 BPA to repay the Treasury, including but not limited to financial reserves (including deferred borrowing), any expense reductions and revenue increases, short-term borrowing available through the Treasury Facility (which availability may be limited by constraints on BPA's remaining borrowing authority), 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 BP-16 rate proceeding, repayments to Treasury required pursuant to the previous exercise of liquidity tools, 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 total of revenue from Power rates 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 shall 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 BP-16 rates, the NFB Adjustment calculation can result in an increase in the annual CRAC Cap set forth in Table B in GRSP II.C if an NFB Trigger Event occurs prior to the fiscal year to which a CRAC is applied.

NFB Adjustment = Financial Effects of Trigger Event(s)

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

See GRSP II.C.1(b) for additional detail.

3. The Emergency NFB Surcharge

The Emergency NFB Surcharge (Surcharge) results in an upward adjustment to specified rates 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 (also referred to as a cash crunch). 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). The Emergency NFB Surcharge is a separate adjustment from the NFB Adjustment.

For the BP-16 rates, the Surcharge may be implemented in FY 2016 if the (a) and (b) events required to impose the Surcharge occur in that fiscal year, or in FY 2017 if the requisite (a) and (b) events occur in that year.

The Surcharge is an upward adjustment to certain rates for FY 2016 or FY 2017 or both. It applies to these Power rates:

- Non-Slice Customer rate (PF-16)
- PF Melded rate (PF-16)
- Industrial Firm Power rate (IP-16)
- New Resource Firm Power rate (NR-16)

The CRAC also applies to these Transmission rates:

- Reserves-based Ancillary and Control Area Services (ACS-16) rates

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 Surcharge revenues total less than the total Financial Effects for Trigger Events in that year, the remaining balance of Financial Effects will be included in an NFB Adjustment to the CRAC Cap for the subsequent year.

4. Calculations for the NFB Emergency Surcharge

(a) Calculating the NFB Surcharge Amount

NFB Surcharge Amount = Financial Effects of Trigger Event

(b) Calculating the PF/IP/NR Surcharge Amount and the ACS Surcharge Amount

The PF/IP/NR Surcharge Amount is 91.8% times the Surcharge Amount.

The ACS Surcharge Amount is 8.2% times the Surcharge Amount.

(c) Converting the PF/IP/NR Surcharge Amount to the PF/IP/NR Surcharge

Once the PF/IP/NR Surcharge Amount is determined, that amount will be converted to a mills-per-kilowatthour Surcharge rate added to the IP and NR rates. The Surcharge rate will be converted to a monthly dollars per one percentage point of Non-Slice TOCA value and added to the Non-Slice Customer rate (making a negative Non-Slice Customer rate less negative).

The PF/IP/NR Surcharge rate is calculated by dividing the PF/IP/NR Surcharge Amount by the most current forecast of kilowatthours of service under PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable months of the applicable year.

The PF/IP/NR Surcharge rate is converted to a monthly dollars per one percentage point of Non-Slice TOCA by multiplying the sum of PF System Shaped Loads for the applicable months by the PF/IP/NR Surcharge rate. The product of this calculation is the dollar amount to be collected through the Non-Slice TOCA billing determinant. The dollar amount to be collected through the Non-Slice TOCA billing determinant will be divided by the sum of the Non-Slice TOCAs and divided again by the applicable months in the fiscal year. The result of this calculation is a monthly dollars per one percentage point of Non-Slice TOCA rate adjustment.

(d) Customer Charges for the PF/IP/NR Surcharge

Line items will be added to the bills during the applicable months of the applicable year for service under PF Melded, IP, and NR rates showing additional charges calculated by multiplying the PF/IP/NR Surcharge rate by the applicable kilowatthours of service.

A line item will be added to the bills during the applicable months of the applicable year for service under PF rates showing an additional charge calculated by multiplying the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment by the Non-Slice TOCA.

(e) Converting the ACS Surcharge Amount to Charges on Customers' Bills

Once the ACS Surcharge Amount is determined, that amount will be passed to Transmission Services. See Transmission GRSP II.G for details of how those Transmission rates subject to the Surcharge will be modified.

(f) Other Rate Adjustments

The PF/IP/NR Surcharge rate will be converted to an annual Surcharge rate. The annual Surcharge rate is calculated as the PF/IP/NR Surcharge rate multiplied by the quotient of the sum of PF System Shaped Loads for the applicable surcharge months divided by the annual sum of PF System Shaped Loads.

The annual Surcharge rate will be applied to the Load Shaping True-Up Rate to create the Surcharge-Adjusted Load Shaping True-Up Rate. The annual Surcharge rate will be applied to the PF Melded Equivalent Energy Scalar, see GRSP II.W.1(b), to create the Surcharge-Adjusted PF Melded Equivalent Energy Scalar.

The PF/IP/NR Surcharge will also be applied to the applicable months of the PF Tier 1 Equivalent energy rates. See GRSP II.Q.

5. 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 2015, 2016, or 2017. 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.

If a Trigger Event occurs in FY 2015, it may result in a Surcharge for FY 2015 if BPA is in a cash crunch in FY 2015. Such a Surcharge would be governed by the BP-14 GRSPs. If BPA is not in a cash crunch, or if a Surcharge implemented pursuant to the BP-14 GRSPs during FY 2015 collects less than the full amount of the FY 2015 Financial Effects, such a Trigger Event could lead to an NFB Adjustment to the CRAC Cap applicable to FY 2016 and 2017, as governed by these BP-16 GRSPs.

If a Trigger Event occurs in FY 2016, it may result in either a Surcharge applicable to FY 2016 rates or an NFB Adjustment to the CRAC Cap applicable to FY 2017 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 2016. All of these possibilities will be governed by these GRSPs.

If a Trigger Event occurs in FY 2017 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 2017, these GRSPs are silent on the implications. Any NFB Adjustment that might apply to FY 2018 rates based on Trigger Events occurring in FY 2017 will be defined later by the 2018 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.

6. 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 2016 or FY 2017, 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 BP-16 rate proceeding, will include a description of the Trigger Event. BPA may elect not to notify Customers of the Trigger Event if BPA estimates the Financial Effects of a Trigger Event to be less than $10 million or BPA expects that neither a CRAC applicable to the subsequent year nor a Surcharge resulting from the Trigger Event applicable to the current year will be implemented.

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 ACNR calculation in July 2015 (for an FY 2016 Adjustment) or September 2016 (for an FY 2017 Adjustment). 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 CRAC Cap applicable to the next year.

If the ACNR is forecast to fall below the CRAC Threshold applicable to the next year, BPA shall conduct a workshop(s) as called for by the CRAC procedures in GRSP II.C. At the workshop(s), 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 will respond to reasonable requests for data and calculations and will accept comments on any of the foregoing topics. At the Customer's request, BPA Account Executives shall provide Customers details of their charges under the Surcharge.

If the CRAC applicable to FY 2016 rates triggers, then on or about July 31, 2015, BPA will post to the BPA Web site the final CRAC calculations, including any NFB Adjustment (see section 2 above) to the CRAC Cap. If the CRAC applicable to FY 2017 rates triggers, then on or about September 30, 2016, BPA will post to the

BPA Web site the final CRAC calculations, including any NFB Adjustment (see section 2 above) to the CRAC Cap.

(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 parties on the service list for the BP-16 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 Account Executives will inform Customers of their charges under the Surcharge.

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

BPA will provide data and assumptions used in these calculations. BPA will respond to relevant requests for data and calculations and will accept comments on any of the foregoing topics.

(c) 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 and the total Surcharge Amount to be recovered from each Customer by September 30 of the fiscal year in which the Surcharge is in effect.

The monthly Surcharge Amount will be included on bills to Customers and will be payable in accordance with the applicable payment provisions of the Customers' contracts. The first monthly Surcharge Amount will be billed no sooner than 30 days following the Final Notification.

(d) Process Following Implementation of Surcharge

Within thirty (30) days of the Final Notification of implementation of a Surcharge described above, BPA will provide notice of two or more meetings to be completed within sixty (60) days of the Final Notification.

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 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 section, 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 occur:

(1) 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; or

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

O. [Reserved for future use]

P. Priority Firm Power (PF) Shaping Option

Prior to the beginning of the rate period, BPA and a Customer purchasing Firm Requirements Power charged under section 2.1 of the PF-16 rate schedule may agree to a PF-16 Tier 1 Customer charge payment schedule for the rate period that differs from the flat monthly charge specified in the PF-16 rate schedule. BPA will, to the maximum extent practicable while ensuring timely BPA cost recovery, accommodate individual Customer requests to "shape" certain PF-16 Tier 1 Customer charges within the fiscal year to mitigate adverse cash flow effects on the Customer. The shaped payments at PF-16 Tier 1 Customer rates will be mutually agreed to by BPA and the Customer. Requests to shape Customer charges during the rate period must be received by BPA no later than September 1, 2015.

This Shaping Option analysis will take into account the cash-flow impacts to the Customer of the Tier 1 charges: the Customer charges; a forecast of monthly Load Shaping charges; a forecast of monthly demand charges; and any applicable rate discounts. BPA and the Customer may agree to 12 monthly Composite Customer charges that the Customer shall pay in each year of the rate period. If further shaping is requested to mitigate a Customer's cash-flow impacts, BPA may also agree to shape the Non-Slice Customer charge.

BPA will accommodate requests to shape Customer charges if the following conditions are met:

1. Equivalent Net Present Value: Forecast revenue from the shaped charges must be equivalent, on a net present value basis, to the revenue BPA would have received for each fiscal year without shaping.

2. No Material Adverse Impacts on BPA's Cash Flow: The aggregate shaping requests do not have a material adverse impact on BPA's overall cash flow, as determined solely by BPA. In order to accommodate multiple shaping requests, BPA will take into account the potential offsetting impacts of all shaping requests. If BPA is not able to accommodate all requests in total due to material adverse impacts on BPA's cash flow, BPA may limit the shaping for individual requests.

Q. Priority Firm Power (PF) Tier 1 Equivalent Rates

The PF Tier 1 Equivalent rates are an expression of the Non-Slice PF Public Tier 1 rates in a traditional HLH and LLH energy form. These rates can be used as a reference when a need arises for Tier 1 rates to be expressed in this manner.

	Energy Rate in mills/kWh		***Demand Rate in $/kW***
Month	***HLH***	***LLH***	***HLH***
October	36.71	32.60	10.02
November	37.41	33.33	10.27
December	38.07	33.67	10.51
January	38.87	33.88	10.79
February	38.50	33.53	10.66
March	34.23	30.92	9.13
April	33.21	29.89	8.76
May	30.95	26.38	7.95
June	32.00	25.96	8.33
July	36.28	30.43	9.87
August	39.15	33.26	10.90
September	40.60	34.55	11.42

R. Remarketing

1. Tier 2 Remarketing for Individual Customers

This credit and fee are applicable to Customers when BPA is remarketing their Tier 2 rate purchase amounts pursuant to section 10 of the CHWM Contract.

(a) Tier 2 Remarketing Rate

(1) For Load Following Customers

Fiscal Year	*Rate in mills/kWh*
2016	27.47
2017	29.63

(2) For Slice/Block and Block Customers

After notice is provided by the Slice/Block or Block Customer, the rate shall be the flat annual equivalent market price forecast for the applicable fiscal year plus any additional costs incurred by BPA in purchasing power from other entities.

(b) Tier 2 Remarketing Billing Determinant

For each applicable Tier 2 rate, the billing determinant is (i) the Customer's contracted annual Tier 2 amount at such rate plus real power losses, less (ii) the Customer's annual Tier 2 load at such rate plus real power losses.

(c) Tier 2 Remarketing Credit

For each Customer, the Tier 2 Remarketing credit is calculated by multiplying the applicable Tier 2 Remarketing Rate and the Tier 2 Remarketing billing determinant. The annual value is divided by 12 to calculate a flat monthly credit.

(d) Tier 2 Remarketing Fee

The fee for remarketing Customers' Tier 2 amounts is zero in FY 2016–2017.

2. Non-Federal Resource with DFS Remarketing

This credit and fee are applicable to Customers when BPA is remarketing their non-Federal resources to which DFS applies, pursuant to section 10 of the CHWM Contract.

(a) DFS Remarketing Rate

For each fiscal year, the DFS Remarketing rate shall be:

Fiscal Year	***Rate in mills/kWh***
2016	27.47
2017	29.63

(b) DFS Remarketing Billing Determinant

For each applicable non-Federal resource to which DFS applies, the billing determinant is (i) the Customer’s total non-Federal resource, less (ii) the amount of the Customer’s non-Federal resource needed to meet Above-RHWM Load, as reflected in the Customer’s CHWM Contract Exhibit A, when updated.

(c) DFS Remarketing Credit

For each Customer, the DFS Remarketing credit is calculated by multiplying the applicable DFS Remarketing Rate and the DFS Remarketing billing determinant. The annual value is divided by 12 to calculate a flat monthly credit.

(d) DFS Remarketing Fee

The fee for remarketing a Customer’s non-Federal resource with DFS amounts is zero in FY 2016–2017.

S. Residential Exchange Program Residential Load

Residential Loads of investor-owned utilities for the rate period are determined pursuant to the definition of Residential Load in section 2 of the 2012 REP Settlement and are shown in Table E below.

Table E
Residential Load (in kWh)

Month	*Avista*	*Idaho*	*NorthWestern*
October	254,399,773	449,427,220	47,071,049
November	286,391,298	432,485,411	51,348,636
December	420,321,296	571,412,065	68,143,968
January	454,730,338	643,022,303	72,747,394
February	426,955,167	646,777,473	66,539,420
March	374,469,095	501,437,402	62,909,111
April	309,851,068	425,493,790	53,084,633
May	274,085,810	459,557,161	48,413,769
June	243,613,640	528,686,504	47,926,071
July	262,544,433	663,892,216	52,069,034
August	303,039,692	747,533,897	55,694,016
September	286,937,433	693,475,174	52,850,224

Month	*PacifiCorp*	*Portland General*	*Puget Sound*
October	583,749,004	578,537,273	766,468,762
November	657,133,518	649,912,673	940,067,549
December	987,429,612	928,228,261	1,271,040,279
January	1,055,914,437	988,358,352	1,383,344,090
February	886,730,182	869,970,113	1,269,404,468
March	755,575,589	755,894,636	1,157,391,506
April	642,732,915	658,188,759	1,009,262,594
May	619,364,358	609,487,580	849,358,465
June	666,920,994	577,985,696	731,718,254
July	707,544,710	640,287,504	748,803,915
August	768,697,230	681,444,938	760,883,048
September	674,001,977	661,683,744	729,693,356

These loads are applicable to each year of the rate period, FY 2016 and FY 2017, and are established pursuant to the 2012 REP Settlement Agreement, Contract No. 11PB-12322.

T. Residential Exchange Program 7(b)(3) Surcharge Adjustment

1. ASC Adjustment

The 7(b)(3) Surcharge 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 the 2012 REP Settlement. As determined in the BP-16 7(i) process, each REP participant’s 7(b)(3) Surcharge is based on its Base PF Exchange rate, its Average System Cost (ASC), and its contract exchange loads. Each REP participant’s 7(b)(3) Surcharge is displayed in the table in section 6.1 of the PF-16 rate schedule and is subject to modification under this GRSP.

In implementing the REP, BPA has identified circumstances where a utility's ASC may be modified during the BPA rate period (*e.g.*, new resource additions, new NLSLs). Subject to limitations in the 2008 ASC Methodology, when BPA modifies a utility's ASC during a BPA rate period, the modified ASC shall be effective on the date specified in BPA's notice to the participating utility confirming the modification of its ASC. Therefore, if a participating utility's ASC differs from the ASC used in establishing rates in section 6.1 of the PF-16 rate schedule, BPA shall adjust the 7(b)(3) Surcharges of all participating utilities to reflect the new ASC.

Such adjustment of 7(b)(3) Surcharges shall be accomplished by substituting all modified ASCs and recomputing the rates in section 6.1 of the PF-16 rate schedule. This recomputation shall be accomplished by:

- Inserting the participating utility's revised ASC, expressed in mills/kWh (equivalent to $/MWh).

- Retaining the forecast exchange load for the participating utility, expressed in gigawatthours, as adopted in the BP-16 7(i) proceeding.

- Multiplying the difference between the ASC and the applicable Base PF Exchange rate by the forecast exchange load to compute the unconstrained benefits for each participant.

- Summing the unconstrained benefits for each participant to compute total unconstrained benefits.

- Computing the difference between the total unconstrained benefits and $437,978,501 (the total REP benefits adopted for the two-year rate period in the BP-16 7(i) proceeding).

- Allocating the computed difference to participants such that the first $153,075,234 (the total REP Refund Amounts for the two-year rate period) is allocated only to the IOU participants and the remainder is allocated to all participants on a pro rata basis referenced to unconstrained benefits.

- Recomputing the IOU adjustments specified in section 6.2 of the 2012 REP Settlement.

- Dividing the recomputed allocated dollars by exchange loads to determine the revised 7(b)(3) Surcharge and adding each revised 7(b)(3) Surcharge to the appropriate Base PF Exchange rate to compute the revised utility-specific PF Exchange rates.

The specific computations that will be performed are displayed on Table 2.4.12 of the Power Rates Study Documentation, BP-16-FS-BPA-01A. This table shall be updated as specified above to perform the actual 7(b)(3) Surcharge adjustments. The adjusted 7(b)(3) Surcharges shall take effect on the day that the utility's modified ASC takes effect. This adjustment shall occur as frequently as ASCs are modified during the two-year rate period the PF Exchange rate herein is in effect.

The adjustment of 7(b)(3) Surcharges shall be updated and published as ASCs are modified. The table can be accessed through BPA's Residential Exchange Program Web site.

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 $437,978,501 in the 7(b)(3) Surcharge calculation in section 1 above 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 $437,978,501 by the same amount. If the load is transferred from a participating utility to another Customer such that BPA expenses are not increased due to the transferred load, then the $437,978,501 will not be reduced. The $437,978,501 cannot be increased through a transfer of load.

U. Resource Support Services and Transmission Scheduling Service

Resource-specific RSS rates will be posted on the BPA Web site.

1. Diurnal Flattening Service Charges, Resource Shaping Charge, and Resource Shaping Charge Adjustment

DFS financially converts the output of a variable, non-dispatchable generating resource into output that is equivalent to a flat amount of power within each diurnal period of a month. Generally, DFS does not apply to small, non-dispatchable resources as such resources are defined in the Customer's CHWM Contract. When DFS charges are coupled with the Resource Shaping Charges, the variable generating resource is financially converted to one that is equivalent to a flat annual block of power. These charges are applied to each resource that is receiving this service. Unless stated otherwise, the resource amounts used in these calculations are either (1) generation amounts specified in the Customer's CHWM Contract Exhibit A (Exhibit A amounts); or (2) planned generation amounts based on hourly generation from the most recent historical year specified in Exhibit D (Exhibit D amounts).

DFS shall apply to the non-Federal resource the Customer is applying to its load and any portion of the resource remarketed by BPA.

(a) DFS Energy Charge

(1) DFS Energy Rate

The RSS module of BPA's Rate Analysis Model calculates the DFS energy rate for each resource. Generally, for each monthly/diurnal period, the sum of planned generation in excess of average monthly/diurnal Exhibit D amounts is multiplied by 25 percent. The result is multiplied by the applicable monthly/diurnal Resource Shaping rate in section 1(c) below. The monthly/diurnal results are summed for the year and divided by the total planned energy from the Exhibit D amounts to calculate the DFS energy rate.

(2) DFS Energy Billing Determinant

The DFS energy billing determinant is the actual generation for the particular resource during the billing month. The actual generation amounts will be either the resource meter readings or resource transmission schedules if the resource requires an e-Tag.

(3) Calculation of DFS Energy Charge

For each resource, the DFS energy charge is calculated by multiplying the DFS energy rate by the DFS energy billing determinant for each month.

(b) DFS Capacity Charge

(1) DFS Capacity Rate

The rates are the monthly PF Tier 1 demand rates shown in section 2.1.2.1 of the PF-16 rate schedule.

(2) DFS Capacity Billing Determinant

The billing determinant is the difference between the resource's monthly average HLH Exhibit D amounts in one year and the calculated monthly firm capacity of the resource.

The RSS module of BPA's Rate Analysis Model calculates monthly firm capacity amounts for each resource. Generally, the firm capacity calculation represents the lowest level of historical generation in a HLH period of a month after accounting for planned outages and forced outages.

(3) Calculation of DFS Capacity Charge

For each resource, the DFS Capacity charge is the lesser of:

(1) the annual sum of (i) the monthly DFS Capacity rates multiplied by (ii) the monthly DFS billing determinants;

or

(2) the annual average Exhibit D amount multiplied by the sum of the monthly PF Tier 1 demand rates.

The result is then divided by 12 to calculate a flat monthly charge that will be specified in Exhibit D of the Customer's CHWM Contract. This charge is take-or-pay, such that if a Customer can no longer apply the resource to load or if its application to load is delayed, the capacity charge shall still apply.

(c) Resource Shaping Charge

(1) Resource Shaping Rate

The monthly/diurnal Resource Shaping rates are equal to the PF Tier 1 Load Shaping rates shown in section 2.1.3.1 of the PF-16 rate schedule.

(2) Resource Shaping Billing Determinant

The billing determinant for each resource is the difference between the planned monthly/diurnal generation from Exhibit D amounts and the annual average Exhibit A amounts for the same year. Generally, the Resource Shaping charge does not apply to small, non-dispatchable resources as such resources are defined in the Customer's CHWM Contract. When DFS is provided to a resource to which RRS also applies, the billing determinant for each resource is the difference between (i) the planned monthly/diurnal generation from Exhibit D amounts and (ii) the sum of the annual average Exhibit A amounts and Resource Remarketed Amounts in Exhibit D for the same year.

(3) Calculation of Resource Shaping Charge

For each resource, the Resource Shaping Charge is calculated by multiplying the Resource Shaping Rate by the Resource Shaping billing determinant for each monthly/diurnal period. The sum of the values is divided by 24 (or 12 if the service applies only in one fiscal year) to calculate a flat monthly charge.

(d) Resource Shaping Charge Adjustment

(1) Resource Shaping Charge Adjustment Rate

The rates are the monthly/diurnal Resource Shaping rates described in section 1(c)(1) above.

(2) Resource Shaping Charge Adjustment Billing Determinant

For each resource, the billing determinant is the difference between the planned monthly/diurnal generation from Exhibit D amounts and the actual monthly/diurnal generation. The actual generation amounts will be either the resource meter readings, or resource transmission schedules if the resource requires an e-Tag. The calculation of the Resource Shaping Charge Adjustment billing determinant will also include energy provided through FORS, TCMS, planned outage replacement, economic dispatch, and unauthorized increases (UAIs) in the determination of actual generation.

(3) Calculation of Resource Shaping Charge Adjustment

For each resource, the Resource Shaping Charge Adjustment is calculated by multiplying the Resource Shaping Charge Adjustment Rate by the Resource Shaping Charge Adjustment billing determinant for each monthly/diurnal period. On a monthly/diurnal basis this calculation can result in either a charge or a credit.

2. Secondary Crediting Service (SCS) Charges

SCS provides a Load Following Customer that dedicates the entire output of a hydroelectric Existing Resource with a credit for the energy produced by that resource that is in excess of the amounts specified in the CHWM Contract Exhibit A (Exhibit A amounts) and a charge for any energy shortfall by the resource from the Exhibit A amounts. There is also an SCS Administrative Charge for providing this service.

When a resource has SCS applied to it, the PF Tier 1 demand and Load Shaping billing determinants will be calculated using the applicable monthly/diurnal Exhibit A amounts instead of either the actual metered values or annual average Exhibit A amounts.

(a) SCS Shortfall Energy Charges and Secondary Energy Credits

(1) SCS Energy Rate

The rates are the monthly/diurnal Resource Shaping rates described in section 1(c) above.

(2) SCS Energy Billing Determinant

For each resource, the billing determinant is the difference between the actual monthly/diurnal generation and monthly/diurnal generation from Exhibit A amounts. The actual generation amounts will be either the resource meter readings, or resource transmission schedules if the resource requires an e-Tag. The actual generation shall include energy amounts provided through TCMS.

(3) Calculation of SCS Shortfall Energy Charge/Secondary Energy Credit

For each resource, the charge or credit is calculated by multiplying the SCS energy rate by the SCS energy billing determinant for each monthly/diurnal period. On a monthly/diurnal basis, this calculation can result in a charge or a credit. If the actual generation exceeds the Exhibit A amount, the Customer will receive a credit. If the actual generation is less than the Exhibit A amount, the Customer will receive a charge.

(b) SCS Administrative Charge

(1) SCS Administrative Rate

The rate is the monthly PF Tier 1 demand rate shown in section 2.1.2.1 of the PF-16 rate schedule.

(2) SCS Administrative Charge Billing Determinant

For each resource, the billing determinant is the monthly HLH Exhibit A amount multiplied by the forced outage rating.

(3) Calculation of SCS Administrative Charge

For each resource, the SCS Administrative Charge is calculated by multiplying the SCS Administrative Rate by the SCS Administrative billing determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The SCS Administrative charge will be specified in Exhibit D of the Customer's CHWM Contract.

3. Forced Outage Reserve Service (FORS) Charges

FORS is an optional service to provide an agreed-upon amount of capacity and energy to Customers that have a qualifying resource that experiences a forced outage. Unless stated otherwise, the resource amounts used in these calculations are those specified in the Customer's CHWM Contract Exhibit D (Exhibit D amounts) and are planned generation amounts based on hourly generation from the most recent historical year.

(a) FORS Capacity Charge

(1) FORS Capacity Rate

Month	***Rate in $/kW***
October	10.02
November	10.27
December	10.51
January	10.79
February	10.66
March	9.13
April	8.76
May	7.95
June	8.33
July	9.87
August	10.90
September	11.42

(2) FORS Capacity Billing Determinant

For each resource, the billing determinant is the monthly firm capacity multiplied by the forced outage rating. The monthly firm capacity is calculated in the manner described under the DFS Capacity billing determinant, section 1(b)(2).

(3) Calculation of FORS Capacity Charge

For each resource, the FORS Capacity Charge is calculated by multiplying the FORS Capacity Rate and the FORS Capacity billing determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The FORS Capacity charge will be specified in Exhibit D of the Customer's CHWM Contract. This charge is take-or-pay, so that if a Customer can no longer apply the resource to load or if its application to load is delayed, the capacity charge shall still apply.

(b) FORS Energy Charge

(1) FORS Energy Rate

The rate for the energy provided during the first 24 hours of a forced outage will be the average of the Powerdex Mid-C hourly index prices (or its replacement) during hours of the forced outage. The rate for energy provided after the first 24 hours of a forced outage will be the diurnal Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index (or its replacement) over the applicable diurnal period for which energy is provided. If any Mid-C price used in computing the average is less than zero, the average of the prices will be computed using a zero price for such hours.

(2) FORS Energy Billing Determinant

The FORS energy billing determinant is the total actual replacement generation a resource requires to meet the planned generation amount specified in Exhibit D of the Customer's CHWM Contract, subject to the FORS energy limits specified therein.

(3) Calculation of FORS Energy Charge

For each resource, the monthly FORS energy charge is calculated by multiplying the FORS energy rate by the FORS energy billing determinant.

4. Transmission Scheduling Service Charge and Transmission Curtailment Management Service Charge

Transmission Scheduling Service (TSS) is a service provided by Power Services to undertake certain scheduling obligations on behalf of the Customer. Transmission Curtailment Management Service (TCMS) is a feature of TSS under which BPA provides either replacement transmission or power to Customers that have a qualifying resource that experiences a transmission event pursuant to the conditions specified in Exhibit F of the CHWM Contract.

(a) TSS Charge

(1) TSS Rate

Fiscal Year	*Rate in mills/kWh*
2016	0.14
2017	0.14

(2) TSS Billing Determinant

The TSS billing determinant is the total kilowatthours of planned generation that the Customer has dedicated to load during the rate period, as specified in Exhibit A of the CHWM Contract. When TSS is provided to a resource to which RRS also applies, the TSS billing determinant for each resource is (i) the total kilowatthours of planned generation that the Customer has dedicated to load during the rate period, as specified in Exhibit A of the CHWM Contract, plus (ii) the RRS Remarketed amounts that will be included in Exhibit D of the CHWM Contract for the same year.

(3) Calculation of TSS Charge

For each eligible resource, the TSS Charge is calculated by multiplying the TSS Rate and the TSS billing determinant for each month of the rate period (or an individual fiscal year if this service applies only in one fiscal year). The sum of the values is divided by 24 (or 12 if the service applies in only one fiscal year) to calculate a flat monthly charge. The charge is subject to a cap (not including OATI registration fee recovery adjustments described below). Charges for Specified Resources are capped such that if the annual cost to the Customer using the TSS rate exceeds $978/month, then the monthly charge is capped at $978/month. Charges for Unspecified ResourceAmounts are capped such that if the annual cost to the Customer using the TSS rate exceeds $2,934/month, then the monthly charge is capped at $2,934/month.

For each TSS Customer, BPA will determine the number of resources receiving TSS. Then the $200 annual OATI registration fee is applied evenly across those resources and divided by 12 months in the applicable fiscal years of the rate period.

(b) TCMS Charge if Replacement Power is Provided

(1) TCMS Rate

The TCMS rate will be the Powerdex Mid-C hourly index price (or its replacement) for the hour the event occurred. If any Mid-C price is less than zero, the TCMS energy rate will be zero for that hour.

(2) TCMS Billing Determinant

The TCMS billing determinant is the total actual kilowatthours of replacement power BPA supplies.

(3) Calculation of TCMS Charge

For each eligible resource, the TCMS Charge is calculated by multiplying the TCMS Rate and the TCMS billing determinant for each hour of the month.

(c) TCMS Charge if Alternative Transmission is Provided

When replacement Point-to-Point transmission is used to deliver the Customer's eligible resource to load using an alternate transmission path, for each resource the TCMS charge is the cost of the additional transmission BPA purchases plus any additional costs, including real power losses associated with using the replacement transmission.

5. Grandfathered Generation Management Service (GMS) Fee

GMS allows a Load Following Customer that dedicated the entire output of an Existing Resource that received GMS during Subscription to run that resource against load and offset its Tier 1 Load.

(a) GMS Reservation Rate

The rate is the monthly PF Tier 1 demand rate shown in section 2.1.2 of the PF rate schedule.

(b) GMS Reservation Billing Determinant

For each resource, the billing determinant is the monthly firm capacity multiplied by the forced outage rating. The monthly firm capacity is calculated in the manner described under the DFS Capacity billing determinant in GRSP II.U.1.b.

(c) Calculation of GMS Reservation Fee

For each resource, the GMS Reservation Fee is calculated by multiplying the GMS Reservation rate and the GMS Reservation billing determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The GMS Reservation Fee will be specified in Exhibit D of the Customer's CHWM Contract.

6. Resource Remarketing Service (RRS) Credits

RRS is an optional service to provide a remarketing credit to Customers that have a qualifying non-Federal resource to which DFS applies that is expected to generate more than a Customer's Above-RHWM load. The non-Federal resource amounts used in these calculations are those specified in the Customer's CHWM Contract Exhibit D RRS section (Exhibit D RRS amounts).

(a) RRS Credit

(1) RRS Rate

For each non-Federal resource, the rate shall be the flat annual equivalent of the PF Load Shaping rates.

(2) RRS Billing Determinant

For each non-Federal resource, the billing determinant is the Exhibit D RRS amount.

(3) Calculation of RRS Credit

For each non-Federal resource, the RRS Credit is calculated by multiplying the RRS Rate and the RRS billing determinant for each applicable year of the rate period. The annual value is divided by 12 to calculate a flat monthly credit.

(b) RRS Fee

The fee for providing RRS to Customers is determined on a case-by-case basis.

V. RHWM Tier 1 System Capability (RT1SC)

The RT1SC is an element of the Tier 1 Load Shaping Charge billing determinant, described in section 2.1.3.2 of the PF-16 rate schedule. RT1SC is the Tier 1 System Firm Critical Output plus RHWM Augmentation. The RT1SC values for the FY 2016–2017 rate period are shown in Table F below.

Table F
FY 2016-2017 RHWM Tier 1 System Capability

	RT1SC in kWh	
Month	***HLH***	***LLH***
October	3,033,357,382	1,728,132,377
November	3,576,839,287	2,163,004,091
December	3,451,735,558	2,138,430,302
January	2,988,470,682	1,862,356,187
February 2016	2,740,931,192	1,640,490,262
February 2017	2,629,201,832	1,584,625,582
March	3,164,137,550	1,926,178,132
April	2,630,827,097	1,606,778,928
May	4,305,965,964	2,391,345,962
June	3,472,759,522	1,965,644,165
July	3,230,114,832	1,728,434,439
August	3,455,063,061	1,756,385,225
September	2,697,717,993	1,684,318,306

W. Slice True-Up Adjustment

Slice Customers shall have an annual Slice True-Up Adjustment for expenses, revenue credits, and adjustments allocated to the Composite cost pool and to the Slice cost pool. The annual Slice True-Up Adjustment shall be calculated for each fiscal year as soon as BPA's audited actual financial data are available (usually in November). See TRM section 2.7, BP-12-A-03.

1. Calculation of the Annual Composite Cost Pool True-Up

(a) Calculation of the Slice True-Up Adjustment Charge for the Composite Cost Pool

Following the end of each fiscal year of the rate period, BPA shall:

(1) subtract:

(i) the forecast annual expenses, revenue credits, and adjustments allocated to the Composite cost pool for the applicable fiscal year of the rate period, from

(ii) the actual expenses, revenue credits, and adjustments in the applicable fiscal year of the rate period that are allocable to the Composite cost pool;

(2) divide the difference determined in (1) above by the sum of TOCAs for that fiscal year adjusted in accordance with TRM section 5.1.1 and the Load Shaping True-Up methodology set forth in TRM section 5.2.4.1 for Load Following Customers; and

(3) multiply the dollar amount in (2) above by each Slice Customer's Slice percentage for the applicable fiscal year.

For each Slice Customer, the dollar amount calculated, which may be positive or negative, constitutes its Slice True-Up Adjustment charge for the Composite cost pool.

The Composite Cost Pool True-Up Table (Table G) contains the forecast expenses, revenue credits, and adjustments that will be the basis, when compared to actual expenses, revenue credits, and adjustments, for the Slice True-Up Adjustment calculation for the Composite cost pool for the applicable fiscal year. Included in these adjustments and credits are the actual Firm Surplus and Secondary Adjustment from Unused RHWM and the actual DSI Revenue Credit described in (b) and (c) below.

(b) Calculation of the Actual Firm Surplus and Secondary Adjustment from Unused RHWM

For purposes of the annual Composite Cost Pool True-Up, the actual Firm Surplus and Secondary Adjustment from Unused RHWM for the applicable fiscal year shall be calculated as the sum of:

(1) the forecast Firm Surplus and Secondary Adjustment from Unused RHWM for the applicable fiscal year developed in the BP-16 7(i) process; and

(2) the Change in PF Composite Customer Charge Revenue for the applicable fiscal year (change can be positive or negative);

Where:

Change in PF Composite Customer Charge Revenue = (sum of actual TOCAs – sum of forecast TOCAs) × monthly Composite Customer rate × 12 months.

TOCAs are expressed as a percentage, *e.g.*, 95 percent.

Sum of actual TOCAs is calculated after the fiscal year and is equal to the forecast sum of TOCAs for Slice/Block and Block Customers, adjusted based on the Annual Net Requirement process in accordance with TRM section 5.1.1. For Load Following Customers, sum of actual TOCAs is adjusted based on TRM section 2.7.1 using information from the Load Shaping True-Up methodology set forth in TRM section 5.2.4.1.

Sum of forecast TOCAs is the sum of TOCAs used to set the PF-16 Composite Customer rate.

and

(3) the Change in Unused RHWM Revenue for the applicable fiscal year (change can be positive or negative).

Where:

Change in Unused RHWM Revenue = (Actual Unused RHWM – Forecast Unused RHWM) × 32.67 mills/kWh.

Actual Unused RHWM = (1.00 – sum of actual TOCAs, expressed as a decimal) × RHWM Tier 1 System Capability for the applicable fiscal year (expressed in aMW) × 8,760 hours (8,784 hours if a leap year)

Forecast Unused RHWM = (1.00 – sum of forecast TOCAs, expressed as a decimal) × RHWM Tier 1 System Capability for the applicable fiscal year (expressed in aMW) × 8,760 hours (8,784 hours if a leap year).

(c) Calculation of the Actual DSI Revenue Credit

For purposes of the annual Composite Cost Pool True-Up, the Actual DSI Revenue Credit for the applicable fiscal year shall be calculated as the sum of:

(1) the forecast DSI Revenue Credit for the applicable fiscal year developed in the BP-16 7(i) process;

(2) (i) the forecast MWh amount used to calculate (1) above for the applicable fiscal year *minus* (ii) the actual MWh amount of DSI sales for the applicable fiscal year, the result multiplied by –17.54 mills/kWh;

and

(3) DSI Take-or-Pay revenues

Where:

Actual kWh amount of DSI sales and DSI Take-or-Pay revenues shall be obtained from BPA data sources

–17.54 mills/kWh is calculated by the equation:

PFMEES – 8.93 mills/kWh

Where:

PFMEES is the PF Melded Equivalent Energy Scalar of –8.61 mills/kWh and is subject to the CRAC, the DDC, and the NFB Emergency Surcharge.

2. Calculation of the Annual Slice Cost Pool True-Up

The Slice Cost Pool True-Up Table (Table H) contains the forecast expenses, revenue credits, and adjustments that will be the basis, when compared to actual expenses, revenue credits, and adjustments, for the Slice True-Up Adjustment calculation for the Slice cost pool for the applicable fiscal year.

Following the end of each fiscal year and pursuant to TRM section 2.7.2, BPA shall:

(a) subtract:

(1) the forecast annual expenses, revenue credits, and adjustments allocated to the Slice cost pool for the applicable fiscal year of the rate period

from

(2) the actual expenses, revenue credits, and adjustments that are allocated to the Slice cost pool for the applicable fiscal year of the rate period;

and

(b) for each Slice Customer, multiply the resulting difference from (a) above by the ratio of (i) the Customer's Slice percentage for the fiscal year in Exhibit K of the Slice/Block Contract to (ii) the sum of all Customers' Slice percentages for the fiscal year in all Exhibit K of the Slice/Block CHWM Contracts.

For each Slice Customer, the dollar amount calculated, which may be positive or negative, constitutes its Slice True-Up Adjustment charge for the Slice cost pool.

Table G
Composite Cost Pool True-Up Table

		Actual Data ($000)	FY 2016 forecast ($000)	FY 2017 forecast ($000)
1	**Operating Expenses**			
2	**Power System Generation Resources**			
3	**Operating Generation**			
4	COLUMBIA GENERATING STATION (WNP-2)		$ 262,948	$ 322,473
5	BUREAU OF RECLAMATION		$ 156,818	$ 158,121
6	CORPS OF ENGINEERS		$ 243,885	$ 250,981
7	LONG-TERM CONTRACT GENERATING PROJECTS		$ 22,303	$ 17,034
8	**Sub-Total**		**$ 685,954**	**$ 748,609**
9	**Operating Generation Settlement Payment and Other Payments**			
10	COLVILLE GENERATION SETTLEMENT		$ 19,323	$ 19,651
11	SPOKANE LEGISLATION PAYMENT		$ -	$ -
12	**Sub-Total**		**$ 19,323**	**$ 19,651**
13	**Non-Operating Generation**			
14	TROJAN DECOMMISSIONING		$ 800	$ 800
15	WNP-1&3 DECOMMISSIONING		$ 800	$ 1,063
16	**Sub-Total**		**$ 1,600**	**$ 1,863**
17	**Gross Contracted Power Purchases**			
18	PNCA HEADWATER BENEFITS		$ 3,000	$ 3,000
19	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)		$ -	$ -
20	**Sub-Total**		**$ 3,000**	**$ 3,000**
21	**Bookout Adjustment to Power Purchases (omit)**			
22	**Augmentation Power Purchases (omit - calculated below)**			
23	AUGMENTATION POWER PURCHASES		$ -	$ -
24	**Sub-Total**		**$ -**	**$ -**
25	**Exchanges and Settlements**			
26	RESIDENTIAL EXCHANGE PROGRAM (REP) (support costs included in support below)		$ 218,976	$ 219,003
27	OTHER SETTLEMENTS		$ -	$ -
28	**Sub-Total**		**$ 218,976**	**$ 219,003**
29	**Renewable Generation**			
30	RENEWABLES (excludes KIII)		$ 30,939	$ 31,483
31	**Sub-Total**		**$ 30,939**	**$ 31,483**
32	**Generation Conservation**			
33	CONSERVATION ACQUISITION		$ 101,932	$ 104,702
34	LOW INCOME WEATHERIZATION & TRIBAL		$ 5,336	$ 5,422
35	ENERGY EFFICIENCY DEVELOPMENT		$ 15,000	$ 7,000
36	DR & SMART GRID		$ 1,245	$ 1,245
37	LEGACY		$ 605	$ 605
38	MARKET TRANSFORMATION		$ 12,531	$ 12,691
39	**Sub-Total**		**$ 136,649**	**$ 131,665**
40	**Power System Generation Sub-Total**		**$ 1,096,440**	**$ 1,155,273**
41				
42	**Power Non-Generation Operations**			
43	**Power Services System Operations**			
44	EFFICIENCIES PROGRAM		$ -	$ -
45	INFORMATION TECHNOLOGY		$ 5,805	$ 5,910
46	GENERATION PROJECT COORDINATION		$ 7,735	$ 7,845
47	SLICE IMPLEMENTATION		$ 1,101	$ 1,131
48	**Sub-Total**		**$ 14,642**	**$ 14,886**
49	**Power Services Scheduling**			
50	OPERATIONS SCHEDULING		$ 10,307	$ 10,496
51	OPERATIONS PLANNING		$ 7,100	$ 7,255
52	**Sub-Total**		**$ 17,406**	**$ 17,751**
53	**Power Services Marketing and Business Support**			
54	POWER R&D		$ 6,033	$ 6,046
55	SALES & SUPPORT		$ 22,139	$ 24,854
56	STRATEGY, FINANCE & RISK MGMT (REP support costs included here)		$ 22,538	$ 22,166
57	EXECUTIVE AND ADMINISTRATIVE SERVICES (REP support costs included here)		$ 4,326	$ 4,402
58	CONSERVATION SUPPORT		$ 9,456	$ 9,731
59	**Sub-Total**		**$ 64,494**	**$ 67,199**
60	**Power Non-Generation Operations Sub-Total**		**$ 96,542**	**$ 99,836**
61	**Power Services Transmission Acquisition and Ancillary Services**			
62	TRANSMISSION and ANCILLARY Services - System Obligations		$ 35,815	$ 35,073
63	3RD PARTY GTA WHEELING		$ 63,567	$ 76,521
64	POWER SERVICES - 3RD PARTY TRANS & ANCILLARY SVCS (omit)		$ -	$ -
65	TRANS ACQ GENERATION INTEGRATION		$ 12,142	$ 12,074
66	TELEMETERING/EQUIP REPLACEMT		$ -	$ -
67	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**		**$ 111,524**	**$ 123,668**
68	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
69	**Fish & Wildlife**		$ 267,000	$ 274,000
70	**USF&W Lower Snake Hatcheries**		$ 32,303	$ 32,949
71	**Planning Council**		$ 11,236	$ 11,446
72	**Environmental Requirements**		$ -	$ -
73	**Fish and Wildlife/USF&W/Planning Council Sub-Total**		**$ 310,539**	**$ 318,395**

Table G, continued
Composite Cost Pool True-Up Table

#		Actual Data ($000)	FY 2016 forecast ($000)		FY 2017 forecast ($000)
74	**BPA Internal Support**				
75	**Additional Post-Retirement Contribution**		$ 19,143		$ 19,478
76	**Agency Services G&A (excludes direct project support)**		$ 53,138		$ 55,168
77	**BPA Internal Support Sub-Total**		**$ 72,281**		**$ 74,646**
78	**Bad Debt Expense**		$ -		$ -
79	**Other Income, Expenses, Adjustments**		$ (25,896)		$ (61,926)
80	**Expense Offset**		$ (71,542)		$ (67,685)
81	**Non-Federal Debt Service**				
82	**Energy Northwest Debt Service**				
83	COLUMBIA GENERATING STATION DEBT SVC		$ 100,810		$ 127,466
84	WNP-1 DEBT SVC		$ 258,325		$ 201,804
85	WNP-3 DEBT SVC		$ 225,942		$ 256,332
86	EN RETIRED DEBT		$ -		$ -
87	**Sub-Total**		**$ 585,077**		**$ 585,602**
88	**Non-Energy Northwest Debt Service**				
89	CONSERVATION DEBT SVC		$ -		$ -
90	COWLITZ FALLS DEBT SVC		$ 7,300		$ 7,303
91	NORTHERN WASCO DEBT SVC		$ 1,931		$ 1,935
92	**Sub-Total**		**$ 9,231**		**$ 9,237**
93	**Non-Federal Debt Service Sub-Total**		**$ 594,308**		**$ 594,839**
94	**Depreciation**		$ 140,201		$ 143,468
95	**Amortization**		$ 82,350		$ 85,034
96	**Total Operating Expenses**		**$ 2,406,748**		**$ 2,465,550**
97					
98	**Other Expenses**				
99	Net Interest Expense		$ 194,389		$ 195,296
100	LDD		$ 39,865		$ 40,464
101	Irrigation Rate Discount Costs		$ 22,146		$ 22,146
102	**Sub-Total**		**$ 256,400**		**$ 257,906**
103	**Total Expenses**		**$ 2,663,149**		**$ 2,723,456**
104					
105	**Revenue Credits**				
106	Generation Inputs for Ancillary, Control Area, and Other Services Revenues		$ 115,750		$ 115,750
107	Downstream Benefits and Pumping Power revenues		$ 17,219		$ 17,219
108	4(h)(10)(c) credit		$ 91,107		$ 87,786
109	Colville and Spokane Settlements		$ 4,600		$ 4,600
110	Energy Efficiency Revenues		$ 15,000		$ 7,000
111	Large Project Revenues		$ -		$ -
112	Miscellaneous revenues		$ 5,750		$ 5,800
113	Renewable Energy Certificates		$ 1,151		$ 648
114	Pre-Subscription Revenues (Big Horn/Hungry Horse)		$ 2,036		$ 1,506
115	Net Revenues from other Designated BPA System Obligations (Upper Baker)		$ 457		$ 466
116	WNP-3 Settlement revenues		$ 34,537		$ 34,537
117	RSS Revenues		$ 3,049		$ 3,468
118	Firm Surplus and Secondary Adjustment (from Unused RHWM)		$ 5,991		$ 2,744
119	Balancing Augmentation Adjustment		$ 1,445		$ 10,543
120	Transmission Loss Adjustment		$ 29,120		$ 29,437
121	Tier 2 Rate Adjustment		$ 725		$ 835
122	NR Revenues		$ 1		$ 1
123	**Total Revenue Credits**		**$ 327,937**		**$ 322,340**
124					
125	**Augmentation Costs (not subject to True-Up)**				
126	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)		$ 12,493		$ 12,603
127	Augmentation Purchases		$ -		$ 20,960
128	**Total Augmentation Costs**		**$ 12,493**		**$ 33,564**
129					
130	**DSI Revenue Credit**				
131	Revenues 91 aMW @ IP rate		$ 33,560		$ 33,469
132	**Total DSI revenues**		**$ 33,560**		**$ 33,469**
133					
134	**Minimum Required Net Revenue Calculation**				
135	Principal Payment of Fed Debt for Power		$ 94,697		$ 109,429
136	Irrigation assistance		$ 61,066		$ 51,482
137	**Sub-Total**		**$ 155,763**		**$ 160,911**
138	Depreciation		$ 140,201		$ 143,468
139	Amortization		$ 82,350		$ 85,034
140	Capitalization Adjustment		$ (45,937)		$ (45,937)
141	Bond Premium Amortization		$ -		$ -
142	PGE WNP3 Settlement		$ (3,524)		$ (3,524)
143	Prepay Revenue Credits		$ (30,600)		$ (30,600)
144	Non-Federal Interest (Prepay)		$ 13,273		$ 12,469
145	**Sub-Total**		**$ 155,763**		**$ 160,910**
146	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expenses		$ (0)		$ 0
147	Minimum Required Net Revenues		**$ -**		**$ 0**
148					
149	Annual Composite Cost Pool (Amounts for each FY)		**$ 2,314,145**		**$ 2,401,211**
150					
151	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**				
152	TRUE-UP AMOUNT (Diff. between actual Comp. Cost Pool and forecast Comp. Cost Pool for applicable FY)				
153	Adjustment of True-Up Amount when actual TOCAs < 100 percent (divide by sum of TOCAs, expressed as a decimal, 100 percent = 1.0)				
154	TRUE-UP ADJUSTMENT CHARGE BILLED (26.61865 percent)				

Table H
Slice Cost Pool True-Up Table

		Actual Data ($000)	FY 2016 forecast ($000)		FY 2017 forecast ($000)
1	**Slice Expenses**				
2					
3					
4	**Total Slice Expenses**		$ -		$ -
5					
6	**Slice Credits**				
7					
8	**Total Slice Credits**		$ -		$ -
9					
10	Annual Slice Cost Pool (Amounts for each FY)		$ -		$ -
11					
12	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR SLICE COST POOL**				
13	TRUE UP AMOUNT (Diff. between actual Slice Cost Pool and forecast Slice COST Pool for applicable FY)				
14					
15	TRUE-UP ADJUSTMENT CHARGE BILLED (100 percent)				

X. Tier 2 Rate TCMS Adjustment

When BPA provides replacement power during a transmission event, a TCMS adjustment will be applied to Customers' bills if they purchase power at the applicable Tier 2 rate. The megawatthours of replacement power will be multiplied by the applicable Powerdex Mid-C hourly index price (or its replacement) for the hour(s) the event occurred. If a Mid-C price is less than zero, the TCMS Adjustment rate will be zero for that hour. The sum of this calculation every month is the Tier 2-related TCMS cost. Each Tier 2 rate Customer's TCMS adjustment will be the Customer's share of the Tier 2-related TCMS cost allocated by total applicable Tier 2 rate sales.

Y. TOCA Adjustment

For each Customer purchasing Firm Requirements Power service under a CHWM Contract, a TOCA for each year of the rate period is calculated in the BP-16 7(i) process and will be made available to the Customer prior to October 1, 2015. A Customer's TOCA for a fiscal year will be revised only as specified below.

The Customer's Adjusted TOCA will be the billing determinant for the Composite, Slice, and Non-Slice Customer charges for the relevant fiscal year. No other Customer's TOCA shall be affected by this TOCA adjustment.

If a TOCA is modified after the October power bill is issued for the fiscal year that the modified TOCA applies, the Customer will be billed retroactively to October 1 of that fiscal year through a one-time billing adjustment. The billing adjustment will be calculated as (i) the sum of the amount billed for the months prior to any mid-year TOCA adjustment minus (ii) the sum of the amount that should have been billed for those same months with the mid-year adjusted TOCA. A positive calculation is a credit to the Customer, and a negative calculation is a charge to the Customer.

1. Load Following Customers

If there is substantial reason for BPA to believe that the Customer's Actual Annual Tier 1 Load will differ from its Forecast Net Requirement determined in the RHWM Process for the applicable year, BPA shall calculate an Adjusted TOCA for that Load Following Customer using an updated estimate of the Customer's Actual Annual Tier 1 Load in place of the Customer's Forecast Net Requirement, as follows:

$$\frac{\text{Updated estimate of Customer's Actual Annual Tier 1 Load}}{\text{Sum of all Customers' RHWMs}} \times 100$$

If the resulting TOCA differs from the TOCA calculated in the BP-16 7(i) process by at least 20 percent, this Adjusted TOCA will be used in place of the TOCA calculated in the BP-16 7(i) process.

The Load Following Customer and BPA may agree to revise a TOCA for a difference of less than 20 percent.

2. Slice/Block or Block Customers

BPA will revise the TOCA of a Slice/Block or Block Customer in three circumstances:

(a) If the Customer's Annual Net Requirement is less than its RHWM and differs from the Forecast Net Requirement used in the BP-16 7(i) process, the Customer's TOCA shall be recalculated for that fiscal year using the Customer's Annual Net Requirement.

(b) If the Customer's Annual Net Requirement equals or exceeds its RHWM, and its Forecast Net Requirement used in the BP-16 7(i) process is less than its RHWM, then the Customer's TOCA shall be recalculated for that fiscal year using the Customer's RHWM.

(c) If a Customer's Annual Net Requirement changes within a fiscal year due to a change in the Customer's Specified Resource amounts within a fiscal year, then the Customer's TOCA shall be recalculated.

Z. Unanticipated Load Service

1. Availability

Unanticipated Load Service (ULS) applies to any request for Firm Requirements Power received after February 1, 2015, that results in an unanticipated increase in a Customer's load placed on BPA during the FY 2016–2017 rate period. Contractual obligations that result from a request for service under section 9(i) of the Northwest Power Act also will be considered ULS. ULS also may apply to a Customer that adds load through retail access, including load that was once served by the Customer and returns under retail access. ULS that is used for replacement of a Customer's new Specified Resource is available only on a temporary basis for the FY 2016–2017 rate period and only when requested pursuant to the required notice.

The following list includes the only sources of Unanticipated Load that will be served by BPA along with the applicable rate schedule under which each type of unanticipated load will be served.

Under PF-16, Unanticipated Load is:

- Load of a New Public (Load Following Customers only)
- Load annexed from investor-owned utilities by a Public (Load Following Customers only)

Under NR-16, Unanticipated Load is:

- New Large Single Loads
- Requirements service requested by investor-owned utilities

Under FPS-16, Unanticipated Load is negotiated on a case-by-case basis.

BPA also will review annexations of load between public utility Customers to assess if there will be an increase in BPA's Firm Requirements Power that will be considered Unanticipated Load.

To start service for Unanticipated Load, the Customer must notify BPA three months in advance of the requested service date for load amounts up to 50 aMW and six months in advance of the requested service date for load amounts greater than 50 aMW. To stop service for Unanticipated Load, the Customer must notify BPA three months in advance of the requested stop date.

ULS will apply for the length of the Customer's contract for Unanticipated Load Service or the conclusion of the rate period on September 30, 2017, whichever occurs first. ULS is a temporary service and may be adjusted annually. For load annexed from investor-owned utilities by a Public (Load Following Customers only) served under PF-16 and for resource replacement of a Public Load Following Customer, the ULS and notification requirements will not apply to unanticipated loads less than 1 (one) aMW per year. These loads will be included in the Customer's Actual Hourly Tier 1 Loads and Actual Monthly/Diurnal Tier 1 Load for billing purposes. Any Unanticipated Load Service in a future rate period must comply with the provisions for ULS for that rate period.

2. Unanticipated Load Service Charge Under the PF-16 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each fiscal year and will be the greater of (1) the rate for the applicable diurnal period from the table below, or (2) the applicable diurnal period forecast market price for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

Month	***Rate in mills/kWh***	
	HLH	***LLH***
October	$27.86	$23.75
November	$28.56	$24.48
December	$29.22	$24.82
January	$30.02	$25.03
February	$29.65	$24.68
March	$25.38	$22.07
April	$24.36	$21.04
May	$22.10	$17.53
June	$23.15	$17.11
July	$27.43	$21.58
August	$30.30	$24.41
September	$31.75	$25.70

(2) Energy Billing Determinant

The energy billing determinant shall be the total amount of Unanticipated Load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

The Demand Rate is equal to the demand rate included in section 2.1.2.1 of the PF-16 rate schedule.

(2) Demand Billing Determinant

The demand billing determinant shall be the lesser of (1) the maximum hourly Unanticipated Load in a month during the HLH minus the average HLH Unanticipated Load amount for the month or (2) 20 percent of the highest hourly Unanticipated Load amount in a month during the HLH.

3. Unanticipated Load Service Charge Under the NR-16 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each fiscal year and shall be the greater of (1) the rate for the applicable diurnal period from the table below, or (2) the applicable diurnal period forecast market price for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

Month	***Rate in mills/kWh***	
	HLH	***LLH***
October	76.33	72.22
November	77.03	72.95
December	77.69	73.29
January	78.49	73.50
February	78.12	73.15
March	73.85	70.54
April	72.83	69.51
May	70.57	66.00
June	71.62	65.58
July	75.90	70.05
August	78.77	72.88
September	80.22	74.17

(2) Energy Billing Determinant

The energy billing determinant is the total of unanticipated NR Hourly Load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

The Demand Rate is equal to the demand rate included in section 2.2 of the NR-16 rate schedule.

(2) Demand Billing Determinant

The Demand billing determinant is the maximum unanticipated NR Hourly Load in a month during HLH, in kilowatts, for the billing period minus the average of the HLH unanticipated NR Hourly Load in a month.

4. Unanticipated Load Service Charge Under the FPS-16 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each fiscal year and shall be the greater of (1) the Resource Replacement rate for the applicable diurnal period (shown in the table below), or (2) the applicable diurnal period forecast market price for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

Month	***Resource Replacement Rate in mills/kWh***	
	HLH	***LLH***
October	$27.86	$23.75
November	$28.56	$24.48
December	$29.22	$24.82
January	$30.02	$25.03
February	$29.65	$24.68
March	$25.38	$22.07
April	$24.36	$21.04
May	$22.10	$17.53
June	$23.15	$17.11
July	$27.43	$21.58
August	$30.30	$24.41
September	$31.75	$25.70

(2) Energy Billing Determinant

The energy billing determinant is the total of Unanticipated Load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

Month	***Rate in $/kW***
October	10.02
November	10.27
December	10.51
January	10.79
February	10.66
March	9.13
April	8.76
May	7.95
June	8.33
July	9.87
August	10.90
September	11.42

(2) Demand Billing Determinant

The Demand billing determinant is the highest maximum unanticipated Resource Replacement load in a month during HLH, in kilowatts, for the billing period minus the average of the HLH unanticipated Resource Replacement load in a month.

AA. Unauthorized Increase (UAI) Charge

The Unauthorized Increase Charge is a charge to any Customer taking more power from BPA than it is contractually entitled to take.

1. Charge for Unauthorized Increase in Demand

The amount of measured demand during an HLH billing hour that exceeds the amount of demand the Customer is contractually entitled to take during that hour shall be billed at 1.25 times the applicable monthly demand rate.

The billing determinant for the UAI demand charge shall be equal to the Customer's single highest HLH demand that is in excess of the Customer's contractual demand entitlement.

For a Load Following Customer, the demand in excess of its demand entitlement shall be the shortfall of its dedicated resources delivered to load on the hour of its Customer System Peak as compared to the Customer's CHWM Contract Exhibit A amount or Exhibit D amount, whichever is applicable.

For a Block Customer or for the Block portion of the Slice/Block product, the Customer's contractual demand entitlement shall be the sum of its Tier 1 and Tier 2 HLH purchase amounts, in accordance with Exhibit C of the CHWM Contract.

For a Slice Customer, the Slice portion of the Slice/Block product will be subject to a demand UAI if the Slice demand is in excess of the Slice entitlement during the peak Delivery Request (Right To Power) HLH of a month. The Slice demand in excess of the Slice entitlement is measured by subtracting (i) the largest final hourly Delivery Request (Right To Power) computed using the Slice Water Routing Simulator for any HLH of a month from (ii) the hourly amount of Slice power delivery (tagged + untagged energy) from BPA for the same HLH of the same month, as such terms are defined in the Slice/Block CHWM Contract.

2. Charge for Unauthorized Increase in Energy

The amount of measured energy or Residential Exchange Program contract load that exceeds the amount of energy the Customer is contractually entitled to take during a diurnal billing period shall be billed the greater of:

(a) 150 mills/kWh;

or

(b) Two times the highest hourly Powerdex Mid-C Index price for firm power for the month in which the unauthorized increase occurs.

In the event the hourly Powerdex Mid-C price 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 between October 1, 2015, and September 30, 2017.

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SECTION III. DEFINITIONS

A. Power Products and Services Offered By BPA Power Services

1. Block Product

As defined in the TRM, the Block Product is BPA's power product defined in section 4 of the Block and Slice/Block CHWM Contracts.

2. 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 Automatic Generation Control automatic deliveries, phone call schedules, or any other standard utility notice provisions. The notice provision and duration of delivery is contract-specific and will affect the value of the capacity 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.

3. 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 Customers under the Priority Firm Power (PF-16), New Resources Firm Power (NR-16), and Firm Power Products and Services (FPS-16) 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 on-line 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 Customer 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.

4. **Energy Shaping Service for NLSL**

Energy Shaping Service is an optional service for Load Following Customers serving a New Large Single Load (NLSL) with a non-Federal resource. ESS includes a capacity component and an energy component. These services shape a Customer's resource energy and capacity output amounts to the actual load of a NLSL.

5. **Firm Requirements Power**

Firm Requirements Power is Federal power that BPA makes continuously available to a Customer to meet BPA's obligations to the Customer under section 5(b) of the Northwest Power Act.

6. **Forced Outage Reserve Service (FORS)**

As defined in the TRM, FORS is a service that provides an agreed-upon amount of capacity and energy to load during the forced outages of a qualifying resource.

7. **General Transfer Agreement Service**

Allows BPA Power Service Customers that are served under General Transfer Agreements (GTAs) or other non-Federal transmission service agreements to receive power and energy over investor-owned or public utilities' systems.

8. **Industrial Firm Power (IP)**

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

9. **Large Project Program (LPP)**

The Large Project Program was established in the BPA Revised Energy Efficiency Post-2011 Implementation Program, and makes available at BPA's discretion monies for the acquisition of conservation above and beyond the Energy Efficiency Incentives program. The costs of LPP acquisitions are recovered through a special rate provision, the Large Project Targeted Adjustment Charge.

10. **Load Following Product**

As defined in the TRM, the Load Following Product is the BPA firm power service under the Load Following CHWM Contract that meets the Customer's Total Retail Load less its Non-Federal Resources obligation on a real-time basis.

11. Load Shaping

BPA provides Load Shaping to Customers with CHWM Contracts purchasing the Load Following Product, the Block Product, or the Block portion of the Slice/Block Product. Load Shaping shapes the Tier 1 System Capability to the monthly/diurnal shape of a Customer's Actual Monthly/Diurnal Tier 1 Load.

12. New Resource Firm Power (NR)

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

(a) for any NLSL, 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 Customer's firm power load within the Pacific Northwest. Deliveries of NR may be reduced or interrupted as permitted by the terms of the Customer's power sales contract with BPA.

NR is guaranteed to be continuously available to the Customer during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and force majeure events.

13. NR Resource Flattening Service (NRFS)

NR Resource Flattening Service (NRFS) is applicable to Load Following Customers that apply the generation output of a non-dispatchable Specified Resource to serve an NLSL.

14. 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 or REPSIA with BPA. PF is not available to serve New Large Single Loads. Deliveries of PF may be reduced or interrupted as permitted by the terms of the Customer's power sales contract with BPA.

PF is guaranteed to be continuously available to the Customer during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and force majeure events.

15. Residential Exchange Program Power

Residential Exchange Program Power is power BPA sells to a Customer pursuant to the REP. Under section 5(c) of the Northwest Power Act, BPA "purchases" power from eligible Pacific Northwest 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 amounts of power purchased and sold are both equal to the utility’s eligible residential and farm load. Benefits must be passed directly to the utility’s residential and farm Customers.

16. Resource Remarketing Service (RRS)

Resource Remarketing Service (RRS) is a service that BPA makes available at its discretion to Load Following Customers where BPA remarkets non-Federal resources on behalf of Customers and provides them with remarketing credits, net of a remarketing fee.

17. Resource Support Services (RSS)

Resource Support Services are used to make resources, either non-Federal or Federal resource acquisitions, financially equivalent to a flat block. RSS are available for all specified non-Federal resources that Load Following Customers contractually dedicate to serve their Total Retail Load and for specified new renewable resources Slice/Block and Block Customers contractually dedicate to serving their Total Retail Load. RSS includes: Diurnal Flattening Service, Forced Outage Reserve Service, Grandfathered Generation Management Service, Secondary Crediting Service, Transmission Scheduling Service and Transmission Curtailment Management Service.

18. Secondary Crediting Service (SCS)

As defined in the TRM, Secondary Crediting Service (SCS) is the optional service offered by BPA that provides a monetary credit for the secondary output from an existing resource that has a firm critical energy component and a secondary energy component. There are two different options for SCS. Under SCS Option 1, the Customer exchanges power generated by its resource with Federal deliveries. Under SCS Option 2, the Customer applies its resource directly to load, and Federal deliveries cover the net load.

19. Slice/Block Product

The Slice/Block Product is the Customer’s purchase obligation under the Slice product and the Block Product to meet the Customer’s regional consumer load obligation under section 3.1 of the Slice/Block CHWM Contract.

B. Definition of Rate Schedule Terms

1. Above-RHWM Load

As defined in the TRM, Above-RHWM Load is the forecast annual Total Retail Load, less Existing Resources, New Large Single Loads, and the Customer’s Rate Period High Water Mark, as determined in the RHWM Process.

2. Actual Monthly/Diurnal Tier 1 Load

As defined in the TRM, the Actual Monthly/Diurnal Tier 1 Load is the amount of the Customer's electric load (measured in kilowatthours) that was served at Tier 1 rates during the relevant monthly/diurnal period.

3. Billing Determinant

(a) A measure of electric power usage at a Customer's metered point of delivery used in the computation of a Customer's bill.

(b) As defined in the Tiered Rate Methodology, a unit of measure for sales of a product or service for which a Customer is billed by BPA.

4. Charge

A charge is the product of a billing determinant and a rate.

5. Contract Demand

The Customer's Contract Demand is the maximum amount of capacity that the Customer agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Customer.

6. Contract Demand Quantity (CDQ)

As defined in the TRM, the Contract Demand Quantity is the monthly quantity of demand (expressed in kilowatts) included in each Customer's CHWM Contract that is subtracted from the Customer System Peak (CSP) as part of the process of determining the Customer's demand charge billing determinant, as calculated in accordance with TRM section 5.3.5.

7. Contract Energy

Contract Energy is the maximum amount of energy that the Customer agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Customer.

8. Contract High Water Mark (CHWM)

As defined in the TRM, the Contract High Water Mark is the amount (expressed in average megawatts) computed for each Customer in accordance with TRM section 4. For each Customer with a CHWM Contract, the CHWM is used to calculate each Customer's RHWM in the RHWM Process for each applicable rate period. The CHWM Contract specifies the CHWM for each Customer.

9. CHWM Contract

As defined in the TRM, the CHWM Contract is the power sales contract between a Customer and BPA that contains a Contract High Water Mark (CHWM) and under which the Customer purchases power from BPA at rates established by BPA in accordance with the TRM.

10. Customer

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

11. 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 GRSP II.F, that is provided by a DSI in a contract with BPA.

12. Energy Efficiency Incentive

The Energy Efficiency Incentive is a funding mechanism that establishes a budget from which BPA funds energy efficiency incentive payments and associated qualified performance payments for Customers with a CHWM Contract.

13. Flat Annual Shape

As defined in the CHWM Contracts, Flat Annual Shape means a distribution of energy having the same average megawatt value of energy in each month of the year.

14. 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) – except for the six holidays specified in NERC Standards. See also Light Load Hours definition.

15. Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index

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 Intercontinental Exchange, Inc.

16. 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.

17. 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 Customer:

(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 Customer.

18. Metered Energy

The Metered Energy for a Customer shall be the number of kilowatthours recorded on the appropriate metering equipment, adjusted as specified in the applicable agreement and delivered to a Customer:

(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.

19. New Public

As defined in the TRM, a New Public is a Public that is not an Existing Customer. (As defined in the TRM, an Existing Customer is a Public that has a CHWM Contract at the time there is an annexation of some portion of its service territory.)

20. NR Hourly Load

The actual hourly amount (measured in kilowatthours) of (1) a Customer's New Large Single Load that is recorded on the metering equipment and adjusted for any applicable resource amounts, as defined in the CHWM Contract; or (2) an investor-owned utility's NR Block amounts as specified in its NR Block Contract.

21. Powerdex Hourly Mid-C Price Index

Average hourly price index for hourly firm power sales of electricity at delivery points along the Mid-Columbia River, as published by Powerdex, Inc.

22. Public

As defined in the TRM, a Public is a public body or cooperative utility or Federal agency eligible to purchase requirements power from BPA pursuant to section 5(b) of the Northwest Power Act.

23. Rate Period High Water Mark (RHWM)

As defined in the TRM, the Rate Period High Water Mark is the amount, calculated by BPA in each RHWM Process pursuant to the formula in TRM section 4.2.1 and expressed in average megawatts, that BPA establishes for each Customer based on the Customer's CHWM and the RHWM Tier 1 System Capability. The maximum planned amount of power a Customer may purchase under Tier 1 rates each fiscal year of the rate period is the RHWM for Load Following Customers and the lesser of RHWM or Annual Net Requirement for Block and Slice/Block Customers.

24. Resource Shaping Charge

As defined in the TRM, the Resource Shaping Charge is the Customer-specific charge or credit as described in TRM section 8.5 that adjusts for the difference in value between a planned resource energy shape that is flat within each monthly/diurnal period (but not necessarily flat when comparing one monthly/diurnal period to another) and an equivalently sized flat annual block (flat for all hours of the fiscal year).

25. Resource Shaping Rate

As defined in the TRM, the Resource Shaping Rate is the rate that is set, as described in TRM section 8.5, equal to the Load Shaping Rate for each monthly/diurnal period.

26. Retail Access

Retail Access is non-discriminatory retail distribution access mandated either by Federal or state law that grants retail electric power consumers the right to choose their electricity supplier.

27. RHWM Tier 1 System Capability (RT1SC)

As defined in the TRM, RHWM Tier 1 System Capability means the Tier 1 System Firm Critical Output plus RHWM Augmentation. The RT1SC table of values may be found at GRSP II.V.

28. Super Peak Credit

As defined in the TRM, the Super Peak Credit is the amount of additional HLH energy, as defined in TRM section 5.3.4, that a Customer contractually commits to provide with non-Federal resources during the Super Peak Period. Such notification must occur by October 31 of the Rate Case Year.

29. Super Peak Period

As defined in the TRM, the Super Peak Period is the hours defined pursuant to the CHWM Contract for each rate period into which a Customer must reshape its HLH energy from its Specified Resources and Unspecified Resource Amounts to receive a Super Peak Credit. The hours BPA establishes for the Super Peak Period may vary by month and will be either two 3-hour periods each day or a single 6-hour period each day.

The Super Peak Period hours for FY 2016–2017 are as follows (HE = Hour Ending):

October – February	HE 8 through HE 10 and HE 18 through HE 20
March – May	HE 7 through HE 12
June – September	HE 13 through HE 18

30. System Shaped Load

As defined in the TRM, the System Shaped Load is the amount of energy a Load Following or Block Customer would receive from BPA under its Tier 1 rates in each of the monthly/diurnal periods in each fiscal year of the rate period if the Customer's TOCA Load was delivered in the shape of the RHWM Tier 1 System Capability through such periods.

31. Tier 1 Cost Allocator (TOCA)

As defined in the TRM, the TOCA is the billing determinant for the Customer charges for each Customer purchasing power at a Tier 1 rate under its CHWM Contract. TOCAs are expressed as percentages and are calculated as specified in TRM section 5.1.1. TOCAs are posted on BPA's Web site.

32. Tier 1 Customer System Peak (Tier 1 CSP)

Tier 1 Customer System Peak is equivalent to Customer System Peak as defined in the TRM. As defined in the TRM, Tier 1 CSP is the Customer's maximum Actual Hourly Tier 1 Load (measured in kilowatts) during the Heavy Load Hours of each month.

33. Total Customer System Peak (CSP or Total CSP)

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

34. Total Retail Load (TRL)

All retail electric power consumption, including electric system losses, within a Customer's electrical system, excluding (i) those loads BPA and the Customer have agreed are nonfirm or interruptible loads; (ii) transfer loads of other utilities served by such Customer; and (iii) any loads not on such Customer's electrical system or not within such Customer's service territory, unless specifically agreed to by BPA.

35. Unanticipated Load

Unanticipated Load is any request by a Customer for Firm Requirements Power received by BPA after February 1 of the ratesetting year that (1) results in an increase in the Customer's load placed on BPA during the ensuing rate period, and (2) was not requested and thus not forecast when setting the rates for that rate period.

36. Wheel Turning Load

Wheel Turning Load is that portion of Total Plant Load that is not integral to a Customer's industrial process and is not a part of a technological allowance. A megawatt amount of Wheel Turning Load shall be defined in the Customer'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

Residential Exchange Program Settlement Customer Refund Amounts in FY 2016–2017

Residential Exchange Program Settlement
Customer Refund Amounts in FY 2016–2017

Section 1. Purpose

The Customer Refund Amount in FY 2016–2017 is a credit on a Customer's power bill pursuant to the 2012 REP Settlement Agreement, Contract No. 11PB-12322 (Settlement). The individual Customer credit is determined in part on the terms of the Settlement and in part on information developed in each rate proceeding.

Section 2. Terms of the Customer Refund Amount

The Customer Refund Amount applies to Customers listed in the table below.

A credit shall appear on the monthly power bills beginning with the month that the rates established in the BP-16 rate proceeding take effect. The total credit for a given fiscal year will be the fiscal year's Total Refund divided into 12 equal monthly amounts. Monthly amounts shall be rounded to the nearest whole dollar amount on the power bill.

Section 3. Definitions

PF-02 Refund is the portion of the Customer Refund Amount provided pursuant to Exhibit B of the Settlement.

Scaled TOCA is the Customer-specific percentage derived from a Customer's BP-16 Final Proposal TOCA as adjusted pursuant to section 3.4 of the REP Settlement Agreement.

TOCA Refund is the annual Refund Amount from section 3.2 of the Settlement ($76,537,617) minus the total annual Customer Specific PF-02 Refund Amount from Exhibit B of the Settlement ($38,269,000) multiplied by the Scaled TOCA. Thus, $76,537,617 – $38,269,000 = $38,268,617, which then is multiplied by the Scaled TOCA.

Total Refund is the sum of the PF-02 Refund Amount and the TOCA Refund Amount.

Section 4. Customer Refund Amounts

As displayed on the following table:

Customer Refund Amounts

BPA Customer ID Number	BPA Customer Name	Customer Specific PF-02 Refund (1)	FY 2016 Scaled TOCA (2)	FY 2017 Scaled TOCA (2)	FY 2016 TOCA Refund	FY 2017 TOCA Refund	FY 2016 Total Refund	FY 2017 Total Refund
10005	Alder Mutual	$3,178	0.0079%	0.0079%	$3,008	$3,015	$6,186	$6,193
10015	Asotin County PUD #1	$ -	0.0083%	0.0083%	$3,176	$3,158	$3,176	$3,158
10024	Benton County PUD #1	$1,074,609	2.9177%	2.9020%	$1,116,559	$1,110,555	$2,191,168	$2,185,164
10025	Benton REA	$365,914	0.9659%	0.9607%	$369,624	$367,637	$735,538	$733,550
10027	Big Bend Elec Coop	$180,557	0.8857%	0.8810%	$338,950	$337,128	$519,508	$517,685
10029	Blachly Lane Elec Coop	$102,877	0.2550%	0.2536%	$97,572	$97,047	$200,449	$199,924
10044	Canby, City of	$146,793	0.2940%	0.2924%	$112,493	$111,888	$259,286	$258,681
10046	Central Electric Coop	$400,537	1.1847%	1.1783%	$453,365	$450,927	$853,901	$851,464
10047	Central Lincoln PUD	$483,285	2.2378%	2.2316%	$856,389	$853,991	$1,339,673	$1,337,275
10055	Albion, City of	$ -	0.0058%	0.0057%	$2,203	$2,191	$2,203	$2,191
10057	Ashland, City of	$161,518	0.3049%	0.3033%	$116,695	$116,068	$278,214	$277,586
10059	Bandon, City of	$55,554	0.1104%	0.1100%	$42,259	$42,086	$97,813	$97,640
10061	Blaine, City of	$60,506	0.1266%	0.1259%	$48,446	$48,186	$108,952	$108,692
10062	Bonners Ferry, City of	$45,589	0.0770%	0.0766%	$29,467	$29,308	$75,055	$74,897
10064	Burley, City of	$105,386	0.2010%	0.2005%	$76,921	$76,732	$182,306	$182,118
10065	Cascade Locks, City of	$17,913	0.0320%	0.0318%	$12,237	$12,179	$30,150	$30,092
10066	Centralia, City of	$164,230	0.3528%	0.3509%	$134,995	$134,269	$299,225	$298,500
10067	Cheney, City of	$108,606	0.2289%	0.2277%	$87,611	$87,140	$196,218	$195,746
10068	Chewelah, City of	$ -	0.0381%	0.0379%	$14,577	$14,499	$14,577	$14,499
10070	Declo, City of	$ -	0.0052%	0.0052%	$1,984	$1,974	$1,984	$1,974
10071	Drain, City of	$19,088	0.0277%	0.0276%	$10,605	$10,548	$29,693	$29,636
10072	Ellensburg, City of	$175,179	0.3471%	0.3452%	$132,835	$132,121	$308,014	$307,300
10074	Forest Grove, City of	$169,141	0.3862%	0.3841%	$147,791	$146,996	$316,932	$316,137
10076	Heyburn, City of	$50,558	0.0697%	0.0693%	$26,682	$26,538	$77,240	$77,096
10078	McCleary, City of	$35,576	0.0515%	0.0514%	$19,717	$19,662	$55,293	$55,238
10079	McMinnville, City of	$593,568	1.2763%	1.2694%	$488,413	$485,787	$1,081,981	$1,079,355
10080	Milton, Town of	$53,707	0.1076%	0.1071%	$41,189	$40,967	$94,896	$94,674
10081	Milton-Freewater, City of	$76,961	0.1453%	0.1451%	$55,598	$55,544	$132,559	$132,505
10082	Minidoka, City of	$ -	0.0017%	0.0017%	$637	$645	$637	$645
10083	Monmouth, City of	$59,603	0.1211%	0.1204%	$46,325	$46,076	$105,928	$105,679
10086	Plummer, City of	$28,254	0.0571%	0.0568%	$21,854	$21,737	$50,108	$49,990
10087	Port Angeles, City of	$517,172	1.2194%	1.2147%	$466,664	$464,847	$983,837	$982,019
10089	Richland, City of	$623,657	1.4988%	1.4907%	$573,568	$570,484	$1,197,225	$1,194,141
10091	Rupert, City of	$72,943	0.1364%	0.1356%	$52,188	$51,907	$125,131	$124,850
10094	Soda Springs, City of	$ -	0.0430%	0.0425%	$16,452	$16,278	$16,452	$16,278

BPA Customer ID Number	BPA Customer Name	Customer Specific PF-02 Refund (1)	FY 2016 Scaled TOCA (2)	FY 2017 Scaled TOCA (2)	FY 2016 TOCA Refund	FY 2017 TOCA Refund	FY 2016 Total Refund	FY 2017 Total Refund
10095	Sumas, Town of	$23,429	0.0527%	0.0524%	$20,174	$20,066	$43,603	$43,495
10097	Troy, City of	$ -	0.0295%	0.0293%	$11,288	$11,228	$11,288	$11,228
10101	Clallam County PUD #1	$520,583	1.1004%	1.0945%	$421,113	$418,849	$941,696	$939,432
10103	Clark County PUD #1	$2,370,948	4.3314%	4.3267%	$1,657,562	$1,655,771	$4,028,511	$4,026,720
10105	Clatskanie PUD	$617,393	1.3437%	1.3365%	$514,224	$511,459	$1,131,617	$1,128,852
10106	Clearwater Power	$125,833	0.3382%	0.3378%	$129,441	$129,265	$255,274	$255,098
10109	Columbia Basin Elec Coop	$ -	0.1754%	0.1745%	$67,121	$66,760	$67,121	$66,760
10111	Columbia Power Coop	$ -	0.0425%	0.0425%	$16,249	$16,266	$16,249	$16,266
10112	Columbia River PUD	$265,444	0.8179%	0.8194%	$312,983	$313,561	$578,428	$579,006
10113	Columbia REA	$ -	0.5456%	0.5426%	$208,779	$207,657	$208,779	$207,657
10116	Consolidated Irrigation District #19	$1,825	0.0029%	0.0029%	$1,109	$1,103	$2,935	$2,929
10118	Consumers Power	$246,076	0.6611%	0.6575%	$252,983	$251,623	$499,059	$497,699
10121	Coos Curry Elec Coop	$229,267	0.5810%	0.5793%	$222,337	$221,709	$451,604	$450,976
10123	Cowlitz County PUD #1	$3,446,817	7.9490%	7.9063%	$3,041,971	$3,025,615	$6,488,788	$6,472,432
10136	Douglas Electric Cooperative	$105,338	0.2634%	0.2628%	$100,818	$100,555	$206,156	$205,893
10142	East End Mutual Electric	$ -	0.0389%	0.0387%	$14,886	$14,806	$14,886	$14,806
10144	Eatonville, City of	$23,238	0.0485%	0.0485%	$18,553	$18,555	$41,792	$41,793
10156	Elmhurst Mutual P & L	$ -	0.4651%	0.4641%	$177,973	$177,606	$177,973	$177,606
10157	Emerald PUD	$376,548	0.6827%	0.6850%	$261,244	$262,159	$637,792	$638,707
10158	Energy Northwest	$20,415	0.0401%	0.0398%	$15,327	$15,233	$35,742	$35,648
10170	Eugene Water & Electric Board	$1,490,101	3.4838%	3.4745%	$1,333,201	$1,329,650	$2,823,302	$2,819,751
10172	U.S. Airforce Base, Fairchild	$60,465	0.0829%	0.0833%	$31,721	$31,872	$92,186	$92,338
10173	Fall River Elec Coop	$152,407	0.4795%	0.4769%	$183,507	$182,521	$335,914	$334,927
10174	Farmers Elec Coop	$ -	0.0073%	0.0073%	$2,808	$2,793	$2,808	$2,793
10177	Ferry County PUD #1	$67,875	0.1688%	0.1679%	$64,609	$64,262	$132,484	$132,137
10179	Flathead Elec Coop	$608,080	2.4146%	2.4016%	$924,021	$919,053	$1,532,101	$1,527,132
10183	Franklin County PUD #1	$471,954	1.6985%	1.6894%	$650,000	$646,505	$1,121,954	$1,118,459
10186	Glacier Elec Coop	$ -	0.3085%	0.3069%	$118,074	$117,439	$118,074	$117,439
10190	Grant County PUD #2	$1,146,092	0.5924%	0.5892%	$226,696	$225,477	$1,372,788	$1,371,569
10191	Grays Harbor PUD #1	$736,828	1.8992%	1.8890%	$726,800	$722,892	$1,463,627	$1,459,719
10197	Harney Elec Coop	$91,382	0.3293%	0.3276%	$126,027	$125,349	$217,409	$216,731
10202	Hood River Elec Coop	$89,783	0.1896%	0.1886%	$72,554	$72,164	$162,337	$161,947
10203	Idaho County L & P	$39,010	0.0899%	0.0894%	$34,416	$34,231	$73,425	$73,240
10204	Idaho Falls Power	$435,271	1.1515%	1.1453%	$440,654	$438,285	$875,925	$873,556
10209	Inland P & L	$ -	1.5594%	1.5510%	$596,769	$593,560	$596,769	$593,560
10230	Kittitas County PUD #1	$48,061	0.1404%	0.1397%	$53,743	$53,454	$101,803	$101,514

BPA Customer ID Number	BPA Customer Name	Customer Specific PF-02 Refund (1)	FY 2016 Scaled TOCA (2)	FY 2017 Scaled TOCA (2)	FY 2016 TOCA Refund	FY 2017 TOCA Refund	FY 2016 Total Refund	FY 2017 Total Refund
10231	Klickitat County PUD #1	$219,238	0.5306%	0.5277%	$203,049	$201,957	$422,287	$421,195
10234	Kootenai Electric Coop	$ -	0.7382%	0.7342%	$282,481	$280,962	$282,481	$280,962
10235	Lakeview L & P (WA)	$261,953	0.4640%	0.4638%	$177,555	$177,486	$439,507	$439,439
10236	Lane County Elec Coop	$154,159	0.4004%	0.3984%	$153,228	$152,466	$307,387	$306,625
10237	Lewis County PUD #1	$720,554	1.5850%	1.5792%	$606,550	$604,357	$1,327,104	$1,324,911
10239	Lincoln Elec Coop (MT)	$ -	0.2007%	0.1994%	$76,792	$76,313	$76,792	$76,313
10242	Lost River Elec Coop	$50,765	0.1379%	0.1371%	$52,762	$52,478	$103,527	$103,243
10244	Lower Valley Energy	$ -	1.2453%	1.2386%	$476,554	$473,992	$476,554	$473,992
10246	Mason County PUD #1	$52,092	0.1301%	0.1294%	$49,778	$49,510	$101,870	$101,603
10247	Mason County PUD #3	$544,117	1.1569%	1.1507%	$442,721	$440,340	$986,838	$984,457
10256	Midstate Elec Coop	$287,247	0.6641%	0.6635%	$254,124	$253,900	$541,371	$541,146
10258	Mission Valley	$ -	0.5399%	0.5445%	$206,604	$208,368	$206,604	$208,368
10259	Missoula Elec Coop	$ -	0.3887%	0.3885%	$148,764	$148,667	$148,764	$148,667
10260	Modern Elec Coop	$ -	0.3750%	0.3762%	$143,518	$143,986	$143,518	$143,986
10273	Nespelem Valley Elec Coop	$35,342	0.0851%	0.0847%	$32,576	$32,401	$67,917	$67,742
10278	Northern Lights	$134,905	0.5200%	0.5172%	$198,999	$197,929	$333,903	$332,833
10279	Northern Wasco County PUD	$169,186	0.9374%	0.9324%	$358,730	$356,801	$527,916	$525,987
10284	Ohop Mutual Light Company	$ -	0.1428%	0.1428%	$54,645	$54,666	$54,645	$54,666
10285	Okanogan County Elec Coop	$33,056	0.0944%	0.0940%	$36,111	$35,967	$69,167	$69,023
10286	Okanogan County PUD #1	$302,445	0.6645%	0.6609%	$254,296	$252,928	$556,740	$555,373
10288	Orcas P & L	$ -	0.3580%	0.3561%	$137,003	$136,266	$137,003	$136,266
10291	Oregon Trail Coop	$535,684	1.1367%	1.1399%	$434,983	$436,222	$970,667	$971,907
10294	Pacific County PUD #2	$263,432	0.5258%	0.5230%	$201,213	$200,131	$464,645	$463,563
10304	Parkland L & W	$ -	0.2027%	0.2025%	$77,589	$77,506	$77,589	$77,506
10306	Pend Oreille County PUD #1	$218,512	0.0812%	0.3709%	$31,060	$141,930	$249,572	$360,442
10307	Peninsula Light Company	$484,256	1.0419%	1.0363%	$398,724	$396,580	$882,980	$880,836
10326	U.S. Naval Base, Bremerton	$216,980	0.4188%	0.4166%	$160,286	$159,421	$377,266	$376,401
10331	Raft River Elec Coop	$81,677	0.5093%	0.5106%	$194,917	$195,388	$276,594	$277,065
10333	Ravalli County Elec Coop	$ -	0.2680%	0.2665%	$102,552	$102,000	$102,552	$102,000
10338	Riverside Elec Coop	$ -	0.0343%	0.0342%	$13,140	$13,069	$13,140	$13,069
10342	Salem Elec Coop	$342,469	0.5451%	0.5437%	$208,619	$208,068	$551,088	$550,537
10343	Salmon River Elec Coop	$126,695	0.1788%	0.1777%	$68,421	$68,018	$195,116	$194,713
10349	Seattle City Light	$2,806,762	7.5830%	7.5422%	$2,901,906	$2,886,303	$5,708,668	$5,693,065
10352	Skamania County PUD #1	$110,458	0.2248%	0.2248%	$86,022	$86,010	$196,480	$196,468
10354	Snohomish County PUD #1	$4,394,837	11.1908%	11.2627%	$4,282,557	$4,310,062	$8,677,394	$8,704,900

BPA Customer ID Number	BPA Customer Name	Customer Specific PF-02 Refund (1)	FY 2016 Scaled TOCA (2)	FY 2017 Scaled TOCA (2)	FY 2016 TOCA Refund	FY 2017 TOCA Refund	FY 2016 Total Refund	FY 2017 Total Refund
10360	Southside Elec Lines	$ -	0.0979%	0.0974%	$37,470	$37,269	$37,470	$37,269
10363	Springfield Utility Board	$490,736	1.3337%	1.3292%	$510,400	$508,685	$1,001,136	$999,422
10369	Surprise Valley Elec Coop	$81,780	0.2364%	0.2366%	$90,463	$90,528	$172,243	$172,308
10370	Tacoma Public Utilities	$2,979,021	5.8241%	5.7928%	$2,228,810	$2,216,826	$5,207,831	$5,195,847
10371	Tanner Elec Coop	$59,409	0.1597%	0.1588%	$61,109	$60,781	$120,519	$120,190
10376	Tillamook PUD #1	$287,525	0.8014%	0.7994%	$306,702	$305,927	$594,227	$593,452
10378	Coulee Dam, City of	$ -	0.0292%	0.0291%	$11,191	$11,130	$11,191	$11,130
10379	Steilacoom, Town of	$35,527	0.0696%	0.0692%	$26,631	$26,488	$62,158	$62,015
10388	Umatilla Elec Coop	$557,880	1.6388%	1.6300%	$627,134	$623,762	$1,185,015	$1,181,643
10391	United Electric Coop	$144,156	0.4339%	0.4315%	$166,036	$165,143	$310,192	$309,299
10406	U.S. DOE Albany Research Center	$3,304	0.0066%	0.0066%	$2,539	$2,525	$5,843	$5,830
10408	U.S. Naval Station, Everett (Jim Cree	$10,783	0.0216%	0.0215%	$8,285	$8,232	$19,067	$19,015
10409	U.S. Naval Submarine Base, Bangor	$151,547	0.2956%	0.2940%	$113,114	$112,505	$264,661	$264,053
10426	U.S. DOE Richland Operations Office	$193,387	0.3773%	0.3785%	$144,373	$144,840	$337,760	$338,227
10434	Vera Irrigation District	$190,495	0.3931%	0.3909%	$150,420	$149,611	$340,914	$340,106
10436	Vigilante Elec Coop	$ -	0.2772%	0.2757%	$106,079	$105,509	$106,079	$105,509
10440	Wahkiakum County PUD #1	$32,517	0.0724%	0.0720%	$27,721	$27,572	$60,238	$60,089
10442	Wasco Elec Coop	$ -	0.1848%	0.1858%	$70,714	$71,099	$70,714	$71,099
10446	Wells Rural Elec Coop	$388,509	1.3862%	1.3787%	$530,473	$527,621	$918,982	$916,129
10448	West Oregon Elec Coop	$48,959	0.1210%	0.1204%	$46,313	$46,060	$95,273	$95,020
10451	Whatcom County PUD #1	$179,980	0.3799%	0.3790%	$145,381	$145,027	$325,361	$325,007
10482	Umpqua Indian Utility Cooperative	$15,681	0.0415%	0.0415%	$15,882	$15,890	$31,563	$31,571
10502	Yakama Power	$7,897	0.1684%	0.1675%	$64,437	$64,091	$72,334	$71,988
10597	Hermiston, City of	$100,167	0.1827%	0.1817%	$69,909	$69,522	$170,076	$169,688
10706	Port of Seattle - SETAC In'tl. Airport	$ -	0.2414%	0.2487%	$92,365	$95,190	$92,365	$95,190
11680	Weiser, City of	$ -	0.0916%	0.0911%	$35,056	$34,868	$35,056	$34,868
12026	Jefferson County PUD #1	$ -	NA	NA	$ -	$ -	$ -	$ -
Total		$38,269,000	100.0000%	100.0000%	$38,268,617	$38,268,617	$76,537,617	$76,537,617

(1) See Exhibit B of REP Settlement Agreement, Contract No. 11PB-12322. US BIA Wapato CHWM was annexed by Yakama Power; therefore the PF-02 Refund Amount is included under Yakama Power.

(2) Adjusted TOCAs are recomputed with Grant CHWM equal to 41.75 aMW, pursuant to Section 3.4 of the Settlement Agreement. Final Scaled TOCAs reallocate headroom (when customers' net requirement is below their RHWM allocated share of the Tier 1 System) among all customers pro rata to Adjusted TOCA percentages.

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Appendix B

Tier 2 Load Growth Rate Customer Charge for FY 2016–2017

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Tier 2 Load Growth Rate Customer Charge for FY 2016–FY 2017

Section 1. Purpose

The Tier 2 Load Growth Rate Customer Charge for FY 2016 and FY 2017 is a monthly charge on a Customer's power bill applicable to Customers that elected the Tier 2 Load Growth Rate service option. The individual customer charge is determined as an allocated share of stranded costs that BPA incurred on behalf of the Tier 2 Load Growth Rate pool.

Section 2. Customer Charge

The monthly charge for each Customer is listed in the table below and shall appear on the Customer's power bills.

BPA Customer ID	Load Growth Customer Name	FY 2016 Monthly Customer Charge	FY 2017 Monthly Customer Charge	BPA Customer ID	Load Growth Customer Name	FY 2016 Monthly Customer Charge	FY 2017 Monthly Customer Charge
10055	Albion, City of	$ 43	$ 52	10246	Mason County PUD #1	$ 1,737	$ 1,682
10005	Alder Mutual	$ -	$ -	10256	Midstate Elec Coop	$ -	$ -
10015	Asotin County PUD #1	$ 124	$ 137	10080	Milton, City of	$ 2,778	$ 2,736
10059	Bandon, City of	$ -	$ 137	10082	Minidoka, City of	$ -	$ -
10025	Benton REA	$ -	$ -	10260	Modern Elec Coop	$ -	$ -
10061	Blaine, City of	$ 3,976	$ 4,097	10083	Monmouth, City of	$ 97	$ 298
10065	Cascade Locks, City of	$ -	$ -	10273	Nespelem Valley Elec Coop	$ -	$ -
10068	Chewelah, City of	$ -	$ -	10284	Ohop Mutual Light Company	$ -	$ -
10109	Columbia Basin Elec Coop	$ 3,312	$ 3,100	10288	Orcas P & L	$ 523	$ 766
10111	Columbia Power Coop	$ -	$ -	10291	Oregon Trail Coop	$ -	$ 2,259
10116	Consolidated Irrigation District #19	$ -	$ -	10304	Parkland L & W	$ -	$ 43
10378	Coulee Dam, Town of	$ 254	$ 397	10086	Plummer, City of	$ 291	$ 458
10070	Declo, City of	$ 102	$ 90	10338	Riverside Elec Coop	$ 825	$ 903
10071	Drain, City of	$ 232	$ 222	10342	Salem Elec Coop	$ -	$ -
10142	East End Mutual Electric	$ 2,125	$ 2,108	10352	Skamania County PUD #1	$ -	$ -
10144	Eatonville, Town of	$ -	$ 14	10360	South Side Electric Co.	$ 3,059	$ 3,128
10156	Elmhurst Mutual P & L	$ -	$ 827	10379	Steilacoom, Town of	$ 728	$ 799
10172	Fairchild, U.S. Airforce Base	$ -	$ -	10095	Sumas, City of	$ 421	$ 473
10174	Farmers Elec Coop	$ 70	$ 76	10097	Troy, City of	$ 820	$ 860
10177	Ferry County PUD #1	$ 4,256	$ 4,343	10406	U.S. DOE Albany Research Center	$ 399	$ 354
10190	Grant County PUD #2	$ 2,185	$ 2,240	10326	U.S. Naval Base, Bremerton	$ -	$ -
10197	Harney Elec Coop	$ 3,005	$ 2,987	10408	U.S. Naval Station, Everett (Jim Creek)	$ -	$ -
10597	Hermiston, City of	$ -	$ -	10409	U.S. Naval Submarine Base, Bangor	$ 194	$ 241
10202	Hood River Elec Coop	$ 3,846	$ 4,192	10482	Umpqua Indian Utility Cooperative	$ -	$ -
10230	Kittitas County PUD #1	$ 4,682	$ 4,527	10440	Wahkiakum County PUD #1	$ 647	$ 572
10235	Lakeview L & P (WA)	$ -	$ -	10442	Wasco Elec Coop	$ -	$ -
10242	Lost River Elec Coop	$ 156	$ 553	11680	Weiser, City of	$ 2,152	$ 2,278

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Appendix C

Slice Billing Adjustment

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Slice Billing Adjustment

Section 1. Purpose

The Slice Billing Adjustment is a charge on a Customer's power bill applicable to Customers that purchased the Slice Product during FY 2012–FY 2015. The individual Customer billing adjustment is an allocated share of costs resulting from the treatment of the WNP-3 settlement with Portland General Electric in the calculation of BP-12 and BP-14 PF rates.

Section 2. Billing Adjustment

The Slice Billing Adjustment for each Customer is listed in the table below. The billing adjustment shall appear on the Customer's November 2015 power bill.

Cust ID	Customer Name	November Bill Adjustment
10024	BENTON PUD	$ 198,817
10103	CLARK PUD	$ 317,162
10105	CLATSKANIE PUD	$ 105,423
10123	COWLITZ	$ 579,685
10157	EMERALD	$ 53,749
10170	EWEB	$ 260,651
10183	FRANKLIN PUD	$ 113,216
10191	GRAYS HARBOR PUD	$ 140,730
10204	IDAHO FALLS	$ 79,781
10231	KLICKITAT PUD	$ 34,319
10237	LEWIS PUD	$ 139,599
10286	OKANOGAN PUD	$ 52,466
10294	PACIFIC PUD	$ 40,928
10306	PEND OREILLE PUD	$ 13,584
10349	SEATTLE	$ 526,331
10354	SNOHOMISH PUD	$ 790,137
10370	TACOMA	$ 430,375

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BONNEVILLE POWER ADMINISTRATION
July 2015