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

2018 Power Rate Schedules and General Rate Schedule Provisions (FY 2018–2019)

October 2017

(Revised June 21, 2018)

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

Bonneville Power Administration's 2018 Power Rate Schedules and General Rate Schedule Provisions, effective October 1, 2017, and contained herein, were approved on an interim basis by the Federal Energy Regulatory Commission on September 26, 2017. *U.S. Dep't of Energy – Bonneville Power Admin.,* 160 FERC ¶ 62,245 (2017).

These Power Rate Schedules and General Rate Schedule Provisions reflect all errata corrections as of the date of publication.

BONNEVILLE POWER ADMINISTRATION

2018 POWER RATE SCHEDULES
AND GENERAL RATE SCHEDULE PROVISIONS

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SCHEDULE PF-18
PRIORITY FIRM POWER RATE

1. Availability

This schedule is available for the contract purchase of Firm Requirements Power by public bodies, cooperatives, and Federal agencies pursuant to Section 5(b) of the Northwest Power Act. 16 U.S.C. § 839c(b). 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.

This schedule is also available for the contract purchase of Residential Exchange Program Power by utilities participating in the Residential Exchange Program under Section 5(c) of the Northwest Power Act. 16 U.S.C. § 839c(c). Purchases are made 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, 2017, this rate schedule supersedes the PF-16 rate schedule. Sales under the PF-18 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	2,123,112	(299,405)	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 website. A customer's TOCA may be revised pursuant to the TOCA Adjustment, GRSP II.G.

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.G.

2.1.2 Demand Charge

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

2.1.2.1 Demand Rate

Month	***Rate in $/kW***
October	10.45
November	10.65
December	11.83
January	11.45
February	11.15
March	9.28
April	7.68
May	6.49
June	6.92
July	9.63
August	10.98
September	10.91

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

aHLH = 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 the Demand Rate Billing Determinant Adjustments, GRSP II.D.

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	26.74	22.49
November	27.27	24.74
December	30.28	26.60
January	29.30	23.94
February	28.54	23.94
March	23.75	20.80
April	19.67	17.54
May	16.63	11.25
June	17.71	9.31
July	24.66	19.05
August	28.11	22.61
September	27.94	22.19

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.

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.A.

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.G.

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 Product Conversion Charge

Customers that have converted from the Slice product to a Non-Slice product beginning October 1, 2017, are subject to a monthly charge.

The charge for each customer is set forth in GRSP Appendix B.

2.1.5 Spill Surcharge

The Spill Surcharge, specified in GRSP Appendix C, is applicable to customers that purchase the Load Following product, the Block product, or the Slice/Block product for the Block portion of the service.

See GRSP Appendix D, Supplemental Information, for applicable FY 2018 and FY 2019 Spill Surcharges.

2.2 Tier 2 Charges

2.2.1 Tier 2 Load Shaping Charge

Pursuant to Section 4.3 of the Tiered Rate Methodology (TRM), 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 customers' CHWM Contracts, Exhibit C, Section 2.5.

2.2.2.1 Short-Term Rate

Fiscal Year	*Rate in mills/kWh*
2018	27.20
2019	24.97

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.

2.2.3.1 Load Growth Rate

Fiscal Year	*Rate in mills/kWh*
2018	47.68
2019	45.42

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.

2.2.4 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.

2.2.4.1 VR1-2014 Rate

Fiscal Year	*Rate in mills/kWh*
2018	51.40
2019	53.02

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.

2.2.5.1 VR1-2016 Rate

Fiscal Year	*Rate in mills/kWh*
2018	46.50
2019	48.02

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 energy rates in Section 3.1.1 are subject to adjustment during the Rate Period pursuant to the Spill Surcharge, specified in GRSP Appendix C.

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

3.1 Energy Charge

3.1.1 Energy Rate

Month	*Rate in mills/kWh*	
	HLH	*LLH*
October	39.40	35.15
November	39.93	37.40
December	42.94	39.26
January	41.96	36.60
February	41.20	36.60
March	36.41	33.46
April	32.33	30.20
May	29.29	23.91
June	30.37	21.97
July	37.32	31.71
August	40.77	35.27
September	40.60	34.85

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	10.45
November	10.65
December	11.83
January	11.45
February	11.15
March	9.28
April	7.68
May	6.49
June	6.92
July	9.63
August	10.98
September	10.91

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 under the PF-18 Rate Schedule, specified in GRSP II.M.2, is applicable to the sale of Firm Requirements Power to serve Unanticipated Loads.

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.I.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.I.2.

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.I.3.

5.4 Grandfathered Generation Management Service (GMS)

Load Following customers dedicating to their Tier 1 Load the entire output of an Existing Resource that received GMS under Subscription are subject to a GMS Reservation Fee specified in GRSP II.I.6.

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.

Investor-Owned Utilities	***Rates in mills/kWh***		
	Base PF Exchange Rates	***7(b)(3) Surcharge***	***PF Exchange Rates***
Avista	50.32	3.5810	53.90370
Idaho Power	50.32	10.7013	61.02400
NorthWestern	50.32	19.0894	69.41220
PacifiCorp	50.32	21.4314	71.75420
Portland General	50.32	17.2283	67.55110
Puget Sound Energy	50.32	14.0924	64.41520
Consumer-Owned Utilities	***Base Tier 1 PF Exchange Rates***	***7(b)(3) Surcharge***	***PF Exchange Rates***
Clark Public Utilities	50.35	3.80	54.15
Snohomish County PUD No 1	50.35	1.43	51.78

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 H.

7. Adjustments, Charges, and Special Rate Provisions

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

GRSP II.	Adjustments, Charges, and Special Rate Provisions	Applicable to:				
		Firm Requirements				REP
		Load Following	Block only and Block Portion of Slice/Block	Slice Portion of Slice/Block	Tier 2	
Calculating Rates (including Discounts and Adjustments)						
A	RHWM Tier 1 System Capability (RT1SC)	X	X			
B	Low Density Discount (LDD)	X	X	X		
C	Irrigation Rate Discount	X	X	X		
D	Demand Rate Billing Determinant Adjustments	X				
E	Load Shaping Charge True-Up Adjustment	X				
F	Tier 2 Rate TCMS Adjustment				X	
G	TOCA Adjustment	X	X	X		
Resource Support Services & Related Services						
I	Resource Support Services and Transmission Scheduling Service	X	X	X		
K	Remarketing	X	X	X		
Transfer Service						
L	Transfer Service Charges	X	X	X		
Other Charges						
M	Unanticipated Load Service	X	X	X		
N	Unauthorized Increase (UAI) Charge	X	X	X		X
Risk Adjustments						
O	Power Cost Recovery Adjustment Clause (Power CRAC)	X	X			
P	Power Reserves Distribution Clause (Power RDC)	X	X			
Q	NFB Mechanisms	X	X			
Slice True-Up						
R	Slice True-Up Adjustment			X		
Residential Exchange Program						
S	Residential Exchange Program Residential Load					X
T	Residential Exchange Program 7(b)(3) Surcharge Adjustment					X

GRSP II.	Adjustments, Charges, and Special Rate Provisions	Applicable to:				
		Firm Requirements				REP
		Load Following	Block only and Block Portion of Slice/Block	Slice Portion of Slice/Block	Tier 2	
Conservation						
U	Conservation Surcharge	X	X	X		
Payment Options						
W	Flexible Priority Firm Power (PF) Rate Option	X	X	X		
X	Priority Firm Power (PF) Shaping Option	X	X	X		
Informational						
Z	Cost Contributions	X	X	X	X	X

GRSP Appendix	Adjustments and Charges	Applicable to:		
		Load Following	Block only and Block Portion of Slice/Block	Slice Portion of Slice/Block
A	REP Settlement Customer Refund Amounts in FY 2018–2019	X	X	X
B	Product Conversion Charge for FY 2018– 2019	X	X	
C	Spill Surcharge	X	X	

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SCHEDULE NR-18
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, 2017, this rate schedule supersedes the NR-16 rate schedule. Sales under the NR-18 rate schedule are subject to the 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	82.70	78.45
November	83.23	80.70
December	86.24	82.56
January	85.26	79.90
February	84.50	79.90
March	79.71	76.76
April	75.63	73.50
May	72.59	67.21
June	73.67	65.27
July	80.62	75.01
August	84.07	78.57
September	83.90	78.15

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects an REP Surcharge of 8.83 mills/kWh.

2.1.1.2 Spill Surcharge

The NR energy rates in Section 2.1.1 are subject to adjustment during the Rate Period pursuant to the Spill Surcharge, specified in GRSP Appendix C.

See GRSP Appendix D, Supplemental Information, for applicable FY 2018 and FY 2019 Spill Surcharges.

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	10.45
November	10.65
December	11.83
January	11.45
February	11.15
March	9.28
April	7.68
May	6.49
June	6.92
July	9.63
August	10.98
September	10.91

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 under the NR-18 Rate Schedule, specified in GRSP II.M.3, is applicable to the sale of Firm Requirements Power to serve Unanticipated Loads.

(Rev. 06/21/2018)

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

The Energy Shaping Service (ESS) for NLSLs Charge, specified in GRSP II.J.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.J.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.***
Low Density Discount (LDD)	B
Demand Rate Billing Determinant Adjustments	D
Energy Shaping Service for NLSLs Charge	J.1
NR Resource Flattening Service Charge	J.2
Unanticipated Load Service	M
Unauthorized Increase (UAI) Charge	N
Power Cost Recovery Adjustment Clause (Power CRAC)	O
Power Reserves Distribution Clause (Power RDC)	P
NFB Mechanisms	Q
Conservation Surcharge	U
Flexible New Resource Firm Power (NR) Rate Option	Y
Cost Contributions	Z

GRSP Appendix	***Adjustments and Charges***
C	Spill Surcharge

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SCHEDULE IP-18
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. 16 U.S.C. § 839c(d).

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, 2017, this rate schedule supersedes the IP-16 rate schedule. Sales under the IP-18 rate schedule are subject to the 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-18 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	48.06	43.81
November	48.59	46.06
December	51.60	47.92
January	50.62	45.26
February	49.86	45.26
March	45.07	42.12
April	40.99	38.86
May	37.95	32.57
June	39.03	30.63
July	45.98	40.37
August	49.43	43.93
September	49.26	43.51

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects an REP Surcharge of 8.83 mills/kWh.

2.1.1.2 Value of Reserves Credit

Each energy rate in the table above reflects a 0.896 mills/kWh credit for the value of the Minimum DSI Operating Reserve – Supplemental.

2.1.1.3 Spill Surcharge

The IP energy rates in Section 2.1.1 are subject to adjustment during the Rate Period pursuant to the Spill Surcharge, specified in GRSP Appendix C.

See GRSP Appendix D, Supplemental Information, for applicable FY 2018 and FY 2019 Spill Surcharges.

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	10.45
November	10.65
December	11.83
January	11.45
February	11.15
March	9.28
April	7.68
May	6.49
June	6.92
July	9.63
August	10.98
September	10.91

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 (15.75 MW) is reduced in part or in full by BPA due to a transfer of service to a BPA preference customer, then the Industrial Demand Adjuster value in the above table will be reduced proportionately.

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.*
Demand Rate Billing Determinant Adjustments	D
DSI Reserves	H
Unauthorized Increase (UAI) Charge	N
Power Cost Recovery Adjustment Clause (Power CRAC)	O
Power Reserves Distribution Clause (Power RDC)	P
NFB Mechanisms	Q
Conservation Surcharge	U
Cost Contributions	Z

GRSP Appendix	*Adjustments and Charges*
C	Spill Surcharge

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SCHEDULE FPS-18
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, 2017, this rate schedule supersedes the FPS-16 rate schedule. Sales under the FPS-18 rate schedule are subject to the 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. 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 7 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).

6.1 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.

7. Services for Non-Federal Resources

7.1 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.I.5.

7.2 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.I.4.

7.3 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.I.7.

8. Unanticipated Load Service

The Unanticipated Load Service Charge under the FPS-18 Rate Schedule, specified in GRSP II.M.4, 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. 16 U.S.C. § 839f(i).

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.***
Unauthorized Increase (UAI) Charge	N
Cost Contributions	Z

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GENERAL RATE SCHEDULE PROVISIONS

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GENERAL RATE SCHEDULE PROVISIONS

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GENERAL RATE SCHEDULE PROVISIONS

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

A. Approval of Rates

BPA has requested that the Federal Energy Regulatory Commission grant approval to make these rate schedules and GRSPs effective on October 1, 2017. 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 associated GRSPs supersede BPA's 2016 Power rate schedules, which became effective October 1, 2015, 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), *codified at* 16 U.S.C. § 832 *et seq.,* the Regional Preference Act (Pub. L. No. 88-552), *codified at* 16 U.S.C. § 837 *et seq.*, the Transmission System Act (Pub. L. No. 93-454), *codified at* 16 U.S.C. § 838 *et seq.,* the Northwest Power Act (Pub. L. No. 96-501), *codified at* 16 U.S.C. § 839 *et seq.,* and the Energy Policy Act of 1992 (Pub. L. No. 102-486), *codified at* 16 U.S.C. § 824(i)-(l).

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. Bill 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 shall be applied each day to any unpaid balance. The late payment charge shall be 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. 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 a 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 Transfer Service 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 Transfer Service Delivery Charge. BPA will not assess the Transfer Service 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 Transfer Service 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 website.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. 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-18 rate schedule. RT1SC is the Tier 1 System Firm Critical Output plus RHWM Augmentation. The RT1SC values for the FY 2018–2019 rate period are shown in Table A below.

Table A
FY 2018-2019 RHWM Tier 1 System Capability

	RT1SC in kWh	
Month	***HLH***	***LLH***
October	3,049,683,621	1,639,154,141
November	3,651,526,424	2,143,520,679
December	3,566,674,910	2,158,780,609
January	3,022,270,092	1,869,585,923
February	2,533,270,239	1,477,102,815
March	3,002,579,936	1,745,556,089
April	2,934,906,901	1,628,742,477
May	4,268,254,324	2,428,578,203
June	3,456,513,955	1,827,109,909
July	3,033,188,044	1,606,277,192
August	3,437,616,056	1,700,777,401
September	2,975,771,428	1,679,408,703

B. 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-18 Composite Customer charge, PF-18 Non-Slice Customer charge, PF-18 Load Shaping charge, PF-18 Load Shaping Charge True-Up Adjustment, and PF-18 Demand charge. The LDD also applies to eligible customers under the PF-18 Melded rate schedule and the NR-18 rate schedule. The LDD shall be applied to only those charges listed in this GRSP II.B.

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-RHWM 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-RHWM 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 (K/I) Ratio

The 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 (C/M) Miles Ratio

The 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 43.83 mills/kWh for FY 2018 and FY 2019.

(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 B below. The eligible discount percentage shall be the sum of the two potential discount percentages for which the customer qualifies, based on Table B. The total eligible discount percentage shall not exceed 7 percent and may be adjusted pursuant to Sections 4, 5, and 6 below.

Table B
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 Sections 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.

Customers receiving the LDD for the first time shall receive the full discount amount as determined in Section 3.

When determining the LDD percentage pursuant to Sections 3 and 4, the calculations shall not include any Additional Adjustment for Very Low Densities as determined in Section 5.

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 the annual 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.

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.

C. 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 11.76 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 of the Contract 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 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.

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 10 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 an 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. 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*
2018	–12.75
2019	–12.75

The Load Shaping Charge True-Up rates are subject to adjustment during the Rate Period by the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); the Emergency NFB Surcharge (GRSP II.Q); and the Spill Surcharge (GRSP Appendix C).

See GRSP Appendix D, Supplemental Information, for adjusted Load Shaping Charge True-Up rates.

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.G, 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.

$$\begin{array}{c}\textit{True-Up Charge}\\ \textit{Billing Determinant}\end{array} = \begin{array}{c}\textit{Absolute value of the Annual Deviation}\\ \textit{minus}\\ \textit{Above-RHWM Load}\end{array}$$

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.

F. Tier 2 Rate TCMS Adjustment

This adjustment will recover the cost BPA incurs as a result of a transmission event (in the form of either a planned transmission outage or a transmission curtailment) along the transmission path, between the Point of Receipt and the Point of Delivery, used to deliver energy associated with the power purchases for the Tier 2 cost pools. In such a transmission event situation, a TCMS adjustment will be applied to customers' bills if they purchase power at the applicable Tier 2 rate. The method used to calculate the aggregate TCMS adjustment is specified in GRSP II.I.5.(b) and (c). The aggregate TCMS adjustment will be allocated to customers based on each customer's proportional energy share of the applicable Tier 2 cost pool.

G. 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-18 7(i) process and will be made available to the customer prior to October 1, 2017. A customer's TOCA for a fiscal year will be revised only as specified below.

The customer's adjusted TOCA will be used to establish 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 to which 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:

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

If the resulting TOCA differs from the TOCA calculated in the BP-18 7(i) process by at least 20 percent, this Adjusted TOCA will be used in place of the TOCA calculated in the BP-18 7(i) process.

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

If the customer's CHWM has changed due to (1) acquiring annexed load from a utility with a CHWM, or (2) having its load annexed by a utility with a CHWM, then the customer's RHWM and TOCA will be updated to account for such change. Such TOCA changes may occur prior to the start of the fiscal year or within the fiscal year.

2. Slice/Block or Block Customers

BPA will revise the TOCA of a Slice/Block or Block customer in four 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-18 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-18 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.

(d) If the customer's CHWM has changed due to (1) acquiring annexed load from a utility with a CHWM, or (2) having its load annexed by a utility with a CHWM, then the customer's RHWM and TOCA will be updated to account for such change. Such TOCA changes may occur prior to the start of the fiscal year or within the fiscal year.

H. DSI Reserves

DSI Value of Reserves Adjustment. Pursuant to Section 7(c)(3) of the Northwest Power Act, a DSI customer's wholesale power bill will be adjusted to reflect the value of the Minimum DSI Operating Reserve – Supplemental. 16 U.S.C. § 839e(c)(3). 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 for Operating Reserves – Supplemental is capped at $7.12 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 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.

I. Resource Support Services and Transmission Scheduling Service

Resource-specific RSS rates will be posted on the BPA website. Unless stated otherwise, the resource generation amounts used in the calculations below that are from the customer's CHWM Contract are (1) amounts specified in monthly/diurnal megawatthour amounts and annual average megawatt amounts in Sections 2, 3, and 4 of Exhibit A (Exhibit A amounts); (2) planned amounts specified in monthly/diurnal megawatthour amounts in Section 2.3.6.1(2) of Exhibit D (Exhibit D planned amounts); or (3) planned amounts listed in monthly/diurnal megawatt-per-hour amounts in Section 2.3.6.1(3) of Exhibit D (Exhibit D hourly average planned amounts).

1. Diurnal Flattening Service Charges

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 defined in the customer's CHWM Contract. When DFS charges are coupled with 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.

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 RAM2018 calculates the DFS energy rate for each resource. Generally, for each monthly/diurnal period, the sum of hourly generation in excess of average monthly/diurnal Exhibit D planned amounts is multiplied by 25 percent. The result is multiplied by the applicable monthly/diurnal Resource Shaping rate in GRSP II.I.2(a)(1) below. The monthly/diurnal results are summed for the year and divided by the total Exhibit D planned amounts for that same year 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-18 rate schedule.

(2) DFS Capacity Billing Determinant

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

The RSS module of BPA's RAM2018 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 planned 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.

2. Resource Shaping Charge and Resource Shaping Charge Adjustment

(a) 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-18 rate schedule.

(2) Resource Shaping Billing Determinant

The billing determinant for each resource is the difference between (1) the monthly/diurnal Exhibit D planned amounts or the monthly/diurnal Exhibit A amounts; and (2) the annual average Exhibit A amount converted to a monthly/diurnal shape (in MWh) using the appropriate monthly/diurnal hours for the same year. Generally, RSC does not apply to small, non-dispatchable

resources as 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 monthly/diurnal Exhibit D planned amounts and (ii) the sum of the annual average Exhibit A amounts and Resource Remarketing 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 in only one fiscal year) to calculate a flat monthly charge.

(b) Resource Shaping Charge Adjustment

(1) Resource Shaping Charge Adjustment Rate

The rates are the monthly/diurnal Resource Shaping rates described in GRSP II.I.2(a)(1) above.

(2) Resource Shaping Charge Adjustment Billing Determinant

For each resource, the billing determinant is the difference between Exhibit D planned 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.

3. Secondary Crediting Service (SCS) Charges

SCS provides a Load Following customer that dedicates the entire output of a hydroelectric Existing Resource with (1) a credit for the energy produced by that resource that is in excess of the Exhibit A amounts, and (2) 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 GRSP II.I.2(a)(1) above.

(2) SCS Energy Billing Determinant

For each resource, the billing determinant is the difference between the actual monthly/diurnal generation and monthly/diurnal 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-18 rate schedule.

(2) SCS Administrative Charge Billing Determinant

For each resource, the billing determinant is the monthly average 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.

4. 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.

(a) FORS Capacity Charge

(1) FORS Capacity Rate

Month	*Rate in $/kW*
October	10.45
November	10.65
December	11.83
January	11.45
February	11.15
March	9.28
April	7.68
May	6.49
June	6.92
July	9.63
August	10.98
September	10.91

(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 in GRSP II.I.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 Exhibit D hourly average planned amount, 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.

5. 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*
2018	0.14
2019	0.14

(2) TSS Billing Determinant

The TSS billing determinants are the annual Exhibit A amounts in kilowatthours. When TSS is provided to a resource to which RRS also applies, the TSS billing determinant for each resource is (1) the annual Exhibit A amounts in kilowatthours plus (2) 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 and Unspecified Resource Amounts serving Above-RHWM Load 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 Resource Amounts serving NLSL and 9(c) export decrement obligations 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

If BPA purchases replacement power during a transmission event for a resource supported by TCMS, then the TCMS charge will be the cost of such purchased power. If BPA does not purchase replacement power, then the TCMS charge will be calculated in accordance with the sections below.

(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

The TCMS Charge shall equal the sum of charges for Bands 1 through 3. For each band, the charge shall be calculated as follows:

Apportioned TCMS billing determinant multiplied by the TCMS Rate multiplied by the Factor.

Where:

Band	Apportioned TCMS Billing Determinant	Factor
	The portion of the TCMS billing determinant that is:	
1	Less than or equal to (i) 1.5 percent of the TSS billing determinant or (ii) 2 MW, whichever is larger	1.00
2	Greater than the apportioned TCMS billing determinant for Band 1, up to and including (i) 7.5 percent of the TSS billing determinant or (ii) 10 MW, whichever is larger	1.10
3	Greater than the apportioned billing determinant for Band 2	1.25

(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.

6. Grandfathered Generation Management Service (GMS)

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 2.1.2.1 of the PF-18 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.I.1(b)(2).

(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.

7. 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 Remarketing Value in GRSP II.K.3.

(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.

J. 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 for NLSL Charge

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 its 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-18 energy rates in Section 2.1.1 of the NR-18 rate schedule to calculate the energy charge (or credit).

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 (1) 1.5 percent of the total monthly measured load of the NLSLs receiving this service, or (2) 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 (1) 7.5 percent of the total monthly measured load of the NLSLs receiving this service, or (2) 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 2018–2019 rate period prior to February 1, 2017. 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-18 rate schedule, Section 2.2.1) to calculate the monthly NR ESS Capacity Charge.

A monthly check will be performed to verify that 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 Charge

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

The NRFS energy rate is a unique 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.

K. 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

For each fiscal year, the Tier 2 Remarketing rate shall be the Remarketing Value in GRSP II.K.3.

(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, as determined by BPA after the time of the notice, 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 2018–2019.

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 the Remarketing Value in GRSP II.K.3.

(b) DFS Remarketing Billing Determinant

For each applicable non-Federal resource to which DFS applies, the billing determinant is (1) the amount of the customer's non-Federal resource, as specified in the customer's CHWM Contract Exhibit A, prior to temporary resource removal; less (2) the amount of the customer's non-Federal resource needed to meet Above-RHWM Load, as specified in the customer's CHWM Contract Exhibit A, when updated for temporary resource removal.

(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 DFS remarketing fee for a customer with a non-Federal resource supported with DFS is zero in FY 2018–2019.

3. Remarketing Value

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

Fiscal Year	*Rate in mills/kWh*
2018	25.20
2019	23.00

L. Transfer Service Charges

Transfer Service applies to BPA Power Service customers that are served under non-Federal transmission service agreements.

1. Transfer Service Delivery Charge

The Transfer Service 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) Transfer Service Delivery Rate

	Rate in $/kW
All months	1.27

(b) Transfer Service Delivery Billing Determinant

The monthly billing determinant for the Transfer Service Delivery Charge 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 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 by transfer service; and (2) the customer is not paying BPA Transmission Services for operating reserve for the customer's load.

(a) Transfer Service Operating Reserve Rate

(1) The rate for the Transfer Service Spinning Operating Reserve Charge shall be equal to the ACS-18 Operating Reserve – Spinning Reserve Service rate.

(2) The rate for the Transfer Service Supplemental Operating Reserve Charge shall be equal to the ACS-18 Operating Reserve – Supplemental Reserve Service rate.

(b) Transfer Service Operating Reserve Billing Determinant

(1) The monthly billing determinant for the Transfer Service Spinning Operating Reserve Charge shall be the same as that used for the applicable ACS-18 Operating Reserve – Spinning Reserve Service rate, except that the load used to calculate the billing determinant for Power Services' charge shall be the metered load of the customer served by transfer (non-BPA Balancing Authority Area load) or a portion thereof (if applicable).

(2) The monthly billing determinant for the Transfer Service Supplemental Operating Reserve Charge shall be the same as that used for the applicable ACS-18 Operating Reserve – Supplemental Reserve Service rate, except that the load used to calculate the billing determinant for Power Services' charge shall be the metered load of the customer served by transfer (non-BPA Balancing Authority Area load) or a portion thereof (if applicable).

3. Transfer Service WECC Charge

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

(a) Transfer Service WECC Rate

	Rate in mills/kWh
All months	0.03

(b) Transfer Service WECC Billing Determinant

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

M. Unanticipated Load Service

1. Availability

Unanticipated Load Service (ULS) applies to any request for Firm Requirements Power received after February 1, 2017, that results in an unanticipated increase in a customer's load placed on BPA during the FY 2018–2019 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 on only a temporary basis for the FY 2018–2019 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-18, 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-18, Unanticipated Load is:
- New Large Single Loads
- Requirements service requested by investor-owned utilities

Under FPS-18, 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, 2019, 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-18 and for resource replacement of a Public Load Following customer, the ULS and notification requirements will not apply to unanticipated loads less than 1 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-18 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, as determined by BPA after the time of the request for load service, for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

Month	***Rate in mills/kWh***	
	HLH	***LLH***
October	39.49	35.24
November	40.02	37.49
December	43.03	39.35
January	42.05	36.69
February	41.29	36.69
March	36.50	33.55
April	32.42	30.29
May	29.38	24.00
June	30.46	22.06
July	37.41	31.80
August	40.86	35.36
September	40.69	34.94

(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-18 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-18 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, as determined by BPA after the time of the request for load service, for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

Month	***Rate in mills/kWh***	
	HLH	***LLH***
October	82.70	78.45
November	83.23	80.70
December	86.24	82.56
January	85.26	79.90
February	84.50	79.90
March	79.71	76.76
April	75.63	73.50
May	72.59	67.21
June	73.67	65.27
July	80.62	75.01
August	84.07	78.57
September	83.90	78.15

(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 2.2.1 of the NR-18 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-18 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, as determined by BPA after the time of the request for load service, 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	39.49	35.24
November	40.02	37.49
December	43.03	39.35
January	42.05	36.69
February	41.29	36.69
March	36.50	33.55
April	32.42	30.29
May	29.38	24.00
June	30.46	22.06
July	37.41	31.80
August	40.86	35.36
September	40.69	34.94

(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	10.45
November	10.65
December	11.83
January	11.45
February	11.15
March	9.28
April	7.68
May	6.49
June	6.92
July	9.63
August	10.98
September	10.91

(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.

N. 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 a 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 for each HLH shall be the sum of its Tier 1 and Tier 2 HLH predetermined hourly schedule amounts, provided by BPA to the customer 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 at 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, 2017, and September 30, 2019.

O. Power Cost Recovery Adjustment Clause (Power CRAC)

The Power CRAC is an upward adjustment to certain rates that can apply to rates during FY 2018 or FY 2019 or both. It applies to these Power rates:

- Non-Slice Customer rate (PF-18)
- PF Melded rate (PF-18)
- Industrial Firm Power rate (IP-18)
- New Resource Firm Power rate (NR-18)

The Power CRAC also applies to these Transmission ACS-18 rates:

- Regulating and Frequency Response Service
- Operating Reserve – Spinning
- Operating Reserve – Supplemental

1. Calculations for the Power CRAC

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 for Power (Power ACNR) for the fiscal year preceding the applicable year. If the forecast Power ACNR is less than the Power CRAC Threshold for that applicable year by at least $5 million, the Power 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 (Power CNR) and Accumulated Calibrated Net Revenue (Power ACNR)

The Power CNR is Power Net Revenue (Power NR) plus the Power Net Revenue Calibration (Power NR Calibration).

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

The Power NR Calibration is the sum of the effects of a class of differences, one difference calculated for each event not forecast in the BP-18 rate case that affects Power NR and Power cash flow differently by more than $5 million. "Power cash flow" here means changes in Financial Reserves Available for Risk Attributed to Power. Such events include certain debt management transactions, settlements of contracts, and others. For each event, the impact of the event on Power NR will be subtracted from the impact on Power cash flow.

The Power ACNR is Power CNR accumulated since the end of FY 2016. A forecast of Power ACNR is used to determine whether the Power CRAC Threshold has been reached, and if so, the required Power CRAC Amount to be collected. The forecast of Power ACNR for use in determining the Power CRAC that will apply to FY 2018 rates will be the forecast of Power CNR for FY 2017. The forecast of Power ACNR for use in determining the Power CRAC that will apply to FY 2019 rates will be the sum of the actual Power CNR for FY 2017 plus the forecast of Power CNR for FY 2018.

(b) Calculating the Power CRAC Amount

The Power CRAC Threshold is an amount of ACNR, below which Power is considered to have experienced an Underrun. The Underrun amount is equal to the Power CRAC Threshold minus forecast Power ACNR.

The Power CRAC Amount is based on the Underrun, limited by the Maximum Power CRAC Recovery Amount (the Power CRAC Cap.) There are four possibilities:

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

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

(3) If the Underrun is greater than $100 million and less than $500 million, the Power 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 Power CRAC Amount is equal to $300 million.

NOTE: In cases (2), (3), and (4) above, if an NFB Adjustment increases the Power 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 Power CRAC Cap and Thresholds are shown in Table C.

Table C
Power CRAC Annual Thresholds and Caps
(dollars in millions)

ACNR Calculated Near End of Fiscal Year	*CRAC Applied to Fiscal Year*	*Threshold Measured in ACNR*	*Threshold Measured in Reserves for Risk*	*Maximum CRAC Recovery Amount (Cap)**
2017	2018	$249	$0	$300
2018	2019	$464	$0	$300

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

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

The PF/IP/NR CRAC Amount is 96.52 percent times the Power CRAC Amount.

The ACS CRAC Amount is 3.48 percent times the Power 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 rates: 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 a 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.H for details of how those Transmission rates subject to the Power CRAC will be modified.

(g) Other Rate Adjustments

The Surcharge rate, calculated pursuant to GRSP II.O.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.E.

The Surcharge rate calculated pursuant to Section 1(c) will be subtracted from the PF Melded Equivalent Energy Scalar to create the CRAC-Adjusted PF Melded Equivalent Energy Scalar. *See* GRSP II.R.1(c).

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

2. Power CRAC Notification Process

BPA shall follow these notification procedures:

(a) Financial Performance Status Reports

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

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) the preliminary, unaudited, end-of-year forecast of Power ACNR.

(b) Notification of Power CRAC Trigger

BPA shall complete a forecast of end-of-year Power ACNR in July 2017 for use in calculating the Power CRAC applicable to rates in FY 2018 and in September 2018 for use in calculating the Power CRAC applicable to rates in FY 2019. If the Power CRAC triggers, then BPA shall notify all customers and rate case parties by late July 2017 of the amount by which BPA intends to adjust rates for FY 2018 due to the Power CRAC, and by late September 2018 of the amount by which BPA intends to adjust rates for FY 2019.

Notification will be posted on BPA's website and will include the following:

1. the forecast of Power ACNR for the current fiscal year
2. the Power NR and the Power NR Calibration for FY 2017 in the case of the Power CRAC applicable to FY 2019 rates
3. the Power CRAC Amount
4. the PF/IP/NR CRAC Amount
5. the PF/IP/NR Surcharge
6. the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment
7. the CRAC-adjusted Load Shaping True-Up Rate
8. the CRAC-adjusted PF Melded Equivalent Energy Scalar
9. the ACS CRAC Amount
10. 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 Power 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 Power CRAC calculations as described above, BPA shall conduct a workshop(s) to explain the Power ACNR calculations, describe the calculation of the Power CRAC Amount and allocations to various rates, and demonstrate that the Power CRAC has been implemented in accordance with these GRSPs. The workshop(s) will provide an opportunity for public comment.

If the Power CRAC applicable to FY 2018 rates triggers, then on or about July 31, 2017, BPA will post to the BPA website the final Power CRAC calculations, including any NFB Adjustment (*see* GRSP II.Q) to the Power CRAC Cap. If the Power CRAC applicable to FY 2019 rates triggers, then on or about September 28, 2018, BPA will post to the BPA website the final Power CRAC calculations, including any NFB Adjustment (*see* GRSP II.Q) to the Power CRAC Cap.

P. Power Reserves Distribution Clause (Power RDC)

The Power RDC is a distribution of financial reserves to purposes such as debt retirement, incremental capital investment, or rate reduction (a Dividend Distribution, or DD) during FY 2018 or FY 2019 or both.

If the RDC quantitative criteria (below) are met, the Administrator will determine how much of any RDC, if any, would be applied to debt reduction, incremental capital investment, a DD, or any other uses.

A DD applies to these Power rates during FY 2018 or FY 2019 or both:

- Non-Slice Customer rate (PF-18)
- PF Melded rate (PF-18)
- Industrial Firm Power rate (IP-18)
- New Resource Firm Power rate (NR-18)

A DD also applies to these Transmission ACS-18 rates:

- Regulating and Frequency Response Service
- Operating Reserve – Spinning Reserve Service
- Operating Reserve – Supplemental Reserve Service

1. Calculations for the Power RDC

Prior to the beginning of each fiscal year of the rate period (that is, each "applicable year"), BPA will forecast the end-of-year Power Accumulated Calibrated Net Revenue

(Power ACNR) and BPA Accumulated Calibrated Net Revenue (BPA ACNR) for the fiscal year preceding the applicable year. If the forecast Power ACNR is greater than the Power RDC Threshold for that applicable year by at least $5 million, and the forecast BPA ACNR is greater than the BPA RDC Threshold for that applicable year by at least $5 million, the Administrator will determine the amount, if any, of a Power RDC. If the Administrator determines that part of the RDC will be a DD, the resulting rate decrease will go into effect beginning on October 1 of the applicable year.

(a) Calculating the BPA ACNR

The BPA ACNR is the sum of the Transmission ACNR and the Power ACNR. *See* Transmission GRSP II.H.1(a) and Power GRSP II.O.1(a).

(b) Calculating the Power RDC Amount

The Power RDC can only trigger if (1) Power ACNR exceeds the Power RDC Threshold, measured in Power ACNR, and (2) BPA ACNR exceeds the BPA RDC Threshold, measured in BPA ACNR.

The Power RDC Amount is the reduction in financial reserves for risk attributed to Power caused by using reserves to retire debt, incrementally fund capital projects, decrease rates by means of a Power DD, or further other Power objectives during the year of application. The Power RDC Amount will be the smallest of the forecast Power ACNR less the Power RDC Threshold, the forecast BPA ACNR less the BPA RDC Threshold, and the Power RDC Cap, or a smaller amount if the Administrator so elects.

Table D
Power RDC Annual Thresholds and Caps
(dollars in millions)

ACNR Calculated Near End of Fiscal Year	*RDC Applied to Fiscal Year*	*Threshold Measured in Power ACNR*	*Threshold Measured in Power Reserves for Risk*	*Maximum RDC Amount (Cap)*
2017	2018	$858	$609	$500
2018	2019	$1073	$609	$500

Table E
BPA RDC Annual Thresholds
(dollars in millions)

ACNR Calculated Near End of Fiscal Year	*RDC Applied to Fiscal Year*	*Threshold Measured in BPA ACNR*	*Threshold Measured in BPA Reserves for Risk*
2017	2018	$506	$606
2018	2019	$758	$606

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

The PF/IP/NR DD Amount is 96.52 percent times the Power DD Amount.

The ACS DD Amount is 3.48 percent times the Power DD Amount.

(d) Converting the PF/IP/NR DD Amount to the PF/IP/NR DD Credit

Once the PF/IP/NR DD Amount is determined, that amount will be converted to a mills per kilowatthour PF/IP/NR DD Credit rate and subtracted from each of the monthly/diurnal PF Melded, IP, and NR energy rates. The mills per kilowatthour PF/IP/NR DD 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 DD Credit rate is calculated by dividing the PF/IP/NR DD 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 DD 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 DD 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.

(e) Power DD 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 DD 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.

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

Once the ACS DD Amount is determined, that amount will be passed to Transmission Services. See Transmission GRSP II.G for details of how the ACS DD Amount affects Transmission ACS-18 rates.

(g) Other Rate Adjustments

The Credit rate calculated pursuant to GRSP II.P.1(d) will be added to the Load Shaping True-Up rate to create the Power DD-Adjusted Load Shaping True-Up rate. *See* GRSP II.E.

The Credit rate calculated pursuant to GRSP II.P.1(d) will be added to the PF Melded Equivalent Energy Scalar to create the Power DD-Adjusted PF Melded Equivalent Energy Scalar. *See* GRSP II.R.1(c).

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

2 Power RDC Notification Process

BPA shall follow these notification procedures:

(a) Financial Performance Status Reports

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

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

(b) Notification of Power RDC Trigger

BPA shall complete a forecast of end-of-year Power ACNR and BPA ACNR in July 2017 for use in calculating the Power RDC for FY 2018, and in September 2018 for use in calculating the Power RDC for FY 2019. If the Power RDC triggers, then BPA shall notify all customers and rate case parties by late July 2017 of the amounts BPA intends to use for FY 2018, and by late September 2018 of the amounts BPA intends to use for FY 2019.

Notification will be posted on BPA's website and will include the following:

1. the forecast of Power ACNR and BPA ANR for the current fiscal year
2. the PNR and the PNR Calibration for FY 2017 in the case of the Power RDC applicable to FY 2019 rates
3. the Power RDC Amount
4. the amounts to be used to retire debt, incrementally fund capital projects or other high-value Power purposes, or adjust rates for FY 2018 due to the Power DD
5. the PF/IP/NR DD Amount
6. the PF/IP/NR Surcharge
7. the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment
8. the RDC-adjusted Load Shaping True-Up rate
9. the RDC-adjusted PF Melded Equivalent Energy Scalar
10. the ACS RDC Amount
11. details about how the ACS DD 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 Power ACNR and BPA 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 Power RDC calculations as described above, BPA shall conduct a workshop(s) to explain the Power ACNR and BPA ACNR calculations, describe the calculation of the Power DD Amount and allocations to various rates, and demonstrate that the Power RDC has been implemented in accordance with these GRSPs. The workshop(s) will provide an opportunity for public comment.

If the Power RDC applicable to FY 2018 rates triggers, then on or about July 31, 2017, BPA will post to the BPA website the final Power RDC calculations. If the Power RDC applicable to FY 2019 rates triggers, then on or about September 28, 2018, BPA will post to the BPA website the final Power RDC calculations.

Q. 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 environmental compliance 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*, No. 3:01-cv-0640-SI, 2017 WL 1829588 (D. Or. Apr. 3, 2017), *amending and superseding* 2017 WL 1135610 (D. Or. Mar. 27, 2017) ("*National Wildlife Federation*"), 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 including unplanned or unexpected implementation measures.

(4) Actions needed for meeting obligations for the development of the Columbia River System Operations Environmental Impact Statement.

(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 and impacts captured by the Spill Surcharge. 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-18 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 Power CRAC Cap for a fiscal year in the rate period if Financial Effects from an NFB Trigger Event(s) occur. For the BP-18 rates, the NFB Adjustment calculation can result in an increase in the annual Power CRAC Cap set forth in Table C in GRSP II.O 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 Power CRAC Cap = Power CRAC Cap from Table C + NFB Adjustment

See GRSP II.O.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-18 rates, the Surcharge may be implemented in FY 2018 if the (a) and (b) events required to impose the Surcharge occur in that fiscal year, or in FY 2019 if the requisite (a) and (b) events occur in that year.

The Surcharge is an upward adjustment to certain rates for FY 2018 or FY 2019 or both. It applies to these Power rates:

- Non-Slice Customer rate (PF-18)
- PF Melded rate (PF-18)
- Industrial Firm Power rate (IP-18)
- New Resource Firm Power rate (NR-18)

The Surcharge also applies to these Transmission ACS-18 rates:

- Regulating and Frequency Response Service
- Operating Reserve – Spinning Reserve Service
- Operating Reserve – Supplemental Reserve Service

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 Power 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 96.52% times the Surcharge Amount.

The ACS Surcharge Amount is 3.48% 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* GRSP II.P.1(f). 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.R.1(c), 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.AA.

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 2017, 2018, or 2019. 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 2017, it may result in a Surcharge for FY 2017 if BPA is in a cash crunch in FY 2017. Such a Surcharge would be governed by the BP-16 GRSPs. If BPA is not in a cash crunch, or if a Surcharge implemented pursuant to the BP-16 GRSPs during FY 2017 collects less than the full amount of the FY 2017 Financial Effects, such a Trigger Event could lead to an NFB Adjustment to the Power CRAC Cap applicable to FY 2018 and 2019, as governed by these BP-18 GRSPs.

If a Trigger Event occurs in FY 2018, it may result in either a Surcharge applicable to FY 2018 rates or an NFB Adjustment to the Power CRAC Cap applicable to FY 2019 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 2018. All of these possibilities will be governed by these BP-18 GRSPs.

If a Trigger Event occurs in FY 2019 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 2019, these GRSPs are silent on the implications. Any NFB Adjustment that might apply to FY 2020 rates based on Trigger Events occurring in FY 2019 will be defined later by the BP-20 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 2018 or FY 2019, 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 website and provided by e-mail to those listed on the service list for the BP-18 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 Power 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 2017 (for an FY 2018 Adjustment) or September 2018 (for an FY 2019 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 Power CRAC Cap applicable to the next year.

If the Power ACNR is forecast to fall below the Power CRAC Threshold applicable to the next year, BPA shall conduct a workshop(s) as called for by the Power CRAC procedures in GRSP II.O.3. 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 Power CRAC applicable to FY 2018 rates triggers, then on or about July 31, 2017, BPA will post to the BPA website the final Power CRAC calculations, including any NFB Adjustment (see Section 2 above) to the Power CRAC Cap. If the Power CRAC applicable to FY 2019 rates triggers, then on or about September 28, 2018, BPA will post to the BPA website the final Power CRAC calculations, including any NFB Adjustment (see Section 2 above) to the Power 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 website and provided by e-mail to parties on the service list for the BP-18 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 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 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 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 7 days after the meeting.

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

(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.

R. Slice True-Up Adjustment

Pursuant to Section 2.7 of the TRM, BP-12-A-03, 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).

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 F) 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-18 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-18 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) × 29.91 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-18 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 –22.24 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.

–22.24 mills/kWh is calculated by the equation:

PFMEES – 9.58 mills/kWh

Where:

PFMEES is the PF Melded Equivalent Energy Scalar of –12.66 mills/kWh and is subject to the Power CRAC, the Power RDC, the NFB Emergency Surcharge, and the Spill Surcharge.

See GRSP Appendix D, Supplemental Information, for adjusted PF Melded Equivalent Energy Scalars.

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

The Slice 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 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 F
Composite Cost Pool True-Up Table

		Actual Data ($000)	FY 2018 forecast ($000)		FY 2019 forecast ($000)
1	**Operating Expenses**				
2	**Power System Generation Resources**				
3	**Operating Generation**				
4	COLUMBIA GENERATING STATION (WNP-2)		270,146		327,354
5	BUREAU OF RECLAMATION		164,609		162,623
6	CORPS OF ENGINEERS		256,057		256,057
7	LONG-TERM CONTRACT GENERATING PROJECTS		12,595		13,687
8	**Sub-Total**		**703,407**		**759,721**
9	**Operating Generation Settlement Payment and Other Payments**				
10	COLVILLE GENERATION SETTLEMENT		22,612		22,997
11	SPOKANE LEGISLATION PAYMENT		-		-
12	**Sub-Total**		**22,612**		**22,997**
13	**Non-Operating Generation**				
14	TROJAN DECOMMISSIONING		1,000		1,000
15	WNP-1&3 DECOMMISSIONING		500		534
16	**Sub-Total**		**1,500**		**1,534**
17	**Gross Contracted Power Purchases**				
18	PNCA HEADWATER BENEFITS		3,100		3,100
19	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)		-		-
20	**Sub-Total**		**3,100**		**3,100**
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)		242,372		242,112
27	OTHER SETTLEMENTS		-		-
28	**Sub-Total**		**242,372**		**242,112**
29	**Renewable Generation**				
30	RENEWABLES (excludes KIII)		28,284		28,902
31	**Sub-Total**		**28,284**		**28,902**
32	**Generation Conservation**				
33	CONSERVATION ACQUISITION (Purchases)		71,785		71,785
34	CONSERVATION INFRASCTRUCTURE		27,149		27,283
35	LOW INCOME WEATHERIZATION & TRIBAL		5,523		5,627
36	REIMBURSABLE ENERGY EFFICIENCY DEVELOPMENT		8,000		8,000
37	DR & SMART GRID		856		854
38	LEGACY		590		590
39	MARKET TRANSFORMATION		12,364		12,049
40	**Sub-Total**		**126,267**		**126,187**
41	**Power System Generation Sub-Total**		**1,127,542**		**1,184,553**
42	**Power Non-Generation Operations**				
43	**Power Services System Operations**				
44	EFFICIENCIES PROGRAM		-		-
45	INFORMATION TECHNOLOGY		6,976		7,294
46	GENERATION PROJECT COORDINATION		6,174		6,409
47	SLICE IMPLEMENTATION		1,024		1,061
48	**Sub-Total**		**14,174**		**14,764**
49	**Power Services Scheduling**				
50	OPERATIONS SCHEDULING		10,054		10,404
51	OPERATIONS PLANNING		8,528		8,416
52	**Sub-Total**		**18,582**		**18,820**
53	**Power Services Marketing and Business Support**				
54	POWER R&D		4,705		4,600
55	SALES & SUPPORT		22,885		23,485
56	STRATEGY, FINANCE & RISK MGMT		15,846		18,305
57	EXECUTIVE AND ADMINISTRATIVE SERVICES		4,119		4,204
58	CONSERVATION SUPPORT		9,094		9,409
59	**Sub-Total**		**56,648**		**60,002**
60	**Power Non-Generation Operations Sub-Total**		**89,404**		**93,586**
61	**Power Services Transmission Acquisition and Ancillary Services**				
62	TRANSMISSION and ANCILLARY Services - System Obligations		33,857		32,924
63	3RD PARTY GTA WHEELING		91,759		92,516
64	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)		2,251		2,292
65	TRANS ACQ GENERATION INTEGRATION		12,480		12,634
66	TELEMETERING/EQUIP REPLACEMT		-		-
67	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**		**140,346**		**140,366**
68	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**				
69	**Fish & Wildlife**		276,713		276,704
70	**USF&W Lower Snake Hatcheries**		33,483		33,483
71	**Planning Council**		11,624		11,914
72	**Environmental Requirements**		-		-
73	**Fish and Wildlife/USF&W/Planning Council Sub-Total**		**321,821**		**322,101**

Table F, continued
Composite Cost Pool True-Up Table

		Actual Data ($000)	FY 2018 forecast ($000)	FY 2019 forecast ($000)
74	**BPA Internal Support**			
75	**Additional Post-Retirement Contribution**		14,962	15,620
76	**Agency Services G&A (excludes direct project support)**		64,391	65,796
77	**BPA Internal Support Sub-Total**		**79,353**	**81,417**
78	**Bad Debt Expense**		-	-
79	**Other Income, Expenses, Adjustments**		1,772	(13,668)
80	**Expense Offset**		(60,500)	(60,500)
81	**Non-Federal Debt Service**			
82	**Energy Northwest Debt Service**			
83	COLUMBIA GENERATING STATION DEBT SVC		184,737	338,592
84	WNP-1 DEBT SVC		60,431	40,738
85	WNP-3 DEBT SVC		236,158	32,139
86	**Sub-Total**		**481,326**	**411,469**
87	**Non-Energy Northwest Debt Service**			
88	COWLITZ FALLS DEBT SVC		7,302	7,304
89	NORTHERN WASCO DEBT SVC		1,934	1,932
90	**Sub-Total**		**9,236**	**9,235**
91	**Non-Federal Debt Service Sub-Total**		**490,562**	**420,704**
92	**Depreciation**		144,092	144,065
93	**Amortization**		86,796	87,458
94	**Total Operating Expenses**		**2,421,187**	**2,400,082**
95	**Other Expenses**			
96	Net Interest Expense		94,511	98,711
97	LDD		41,010	41,971
98	Irrigation Rate Discount Costs		22,128	22,128
99	**Sub-Total**		**157,648**	**162,809**
100	**Total Expenses**		**2,578,835**	**2,562,892**
101	**Revenue Credits**			
102	Generation Inputs for Ancillary, Control Area, and Other Services Revenues		108,430	101,519
103	Downstream Benefits and Pumping Power revenues		16,829	16,829
104	4(h)(10)(c) credit		93,172	91,526
105	Colville and Spokane Settlements		4,600	4,600
106	Energy Efficiency Revenues		8,000	8,000
107	Large Project Revenues		-	-
108	Miscellaneous revenues		7,200	7,200
109	Renewable Energy Certificates		-	-
110	Pre-Subscription Revenues (Big Horn/Hungry Horse)		-	-
111	Net Revenues from other Designated BPA System Obligations (Upper Baker)		395	395
112	WNP-3 Settlement revenues		15,959	15,959
113	RSS Revenues		3,082	3,102
114	Firm Surplus and Secondary Adjustment (from Unused RHWM)		30,246	13,324
115	Balancing Augmentation Adjustment		(1,364)	8,511
116	Transmission Loss Adjustment		31,568	32,060
117	Tier 2 Rate Adjustment		1,076	1,273
118	NR Revenues		1	1
119	**Total Revenue Credits**		**319,193**	**304,298**
120				
121	**Augmentation Costs (not subject to True-Up)**			
122	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)		12,393	12,503
123	Augmentation Purchases		-	12,211
124	**Total Augmentation Costs**		**12,393**	**24,714**
125				
126	**DSI Revenue Credit**			
127	Revenues 61 aMW and 88 aMW @ IP rate		23,140	33,392
128	**Total DSI revenues**		**23,140**	**33,392**
129				
130	**Minimum Required Net Revenue Calculation**			
131	Principal Payment of Fed Debt for Power		135,220	173,621
132	Repayment of Non-Federal Obligations		220,252	-
133	Irrigation assistance		27,234	56,573
134	**Sub-Total**		**382,706**	**230,194**
135	Depreciation		144,092	144,065
136	Amortization		86,796	87,458
137	Capitalization Adjustment		(45,937)	(45,937)
138	Non-Cash Expenses		-	-
139	Customer Proceeds		-	-
140	Bond Premium Amortization		-	-
141	PGE WNP3 Settlement		(3,524)	(3,524)
142	Prepay Revenue Credits		(30,600)	(30,600)
143	Non-Federal Interest (Prepay)		11,628	10,747
144	**Sub-Total**		**162,454**	**162,210**
145	Principal Payment of Fed Debt and Non-Fed Debt plus Irrigation assistance exceeds non cash expenses		220,252	67,984
146	Minimum Required Net Revenues		**220,252**	**67,984**
147				
148	Annual Composite Cost Pool (Amounts for each FY)		**2,469,148**	**2,317,899**
149				
150	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**			
151	TRUE-UP AMOUNT (Diff. between actual Comp. Cost Pool and forecast Comp. Cost Pool for applicable FY)			
152	Adjustment of True-Up Amount when actual TOCAs < 100 percent (divide by sum of TOCAs, expressed as a decimal, 100 percent = 1.0)			
153	TRUE-UP ADJUSTMENT CHARGE BILLED (22.7358 percent)			

Table G
Slice Cost Pool True-Up Table

		Actual Data ($000)	FY 2018 forecast ($000)		FY 2019 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)				

S. Residential Exchange Program Residential Load

Residential Loads of investor-owned utilities for the rate period are shown in Table H below. These loads are applicable to each year of the rate period, FY 2018 and FY 2019, and are established pursuant to Section 2 of the 2012 REP Settlement Agreement, REP-12-A-02A (misfiled as REP-12-A-02-AP01) (2012 REP Settlement).

Table H
Residential Load for the BP-18 Rate Period (in kWh)

Month	*Avista*	*Idaho*	*NorthWestern*
October	235,058,847	435,053,509	45,442,425
November	280,401,356	406,737,838	50,050,342
December	402,323,201	546,939,132	65,530,507
January	448,767,477	621,373,273	76,140,905
February	389,685,194	540,206,424	63,494,837
March	323,113,169	457,486,177	57,263,262
April	285,615,055	441,139,602	51,199,781
May	246,791,932	461,080,754	47,548,441
June	250,942,828	535,363,130	49,566,121
July	295,440,073	709,910,515	53,944,669
August	292,870,148	693,674,670	54,789,515
September	276,911,520	625,157,570	49,876,769

Month	*PacifiCorp*	*Portland General*	*Puget Sound*
October	568,701,170	546,339,154	763,865,291
November	646,820,692	610,880,258	904,657,032
December	942,864,884	863,874,792	1,232,152,398
January	987,012,434	929,727,589	1,339,430,067
February	790,439,066	739,082,355	1,168,986,915
March	694,242,108	677,540,079	1,062,152,132
April	620,508,582	623,900,766	914,128,051
May	598,230,633	574,767,922	780,817,339
June	648,469,184	604,283,089	757,238,768
July	767,393,613	669,077,625	763,012,726
August	747,902,078	671,109,286	773,209,333
September	677,968,915	643,249,169	749,716,387

T. Residential Exchange Program 7(b)(3) Surcharge 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-18 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-18 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, changes in service territory). 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-18 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-18 rate schedule. This recomputation shall be accomplished by:

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

2. Retaining the forecast exchange load for the participating utility, expressed in gigawatthours, as adopted in the BP-18 7(i) proceeding.

3. 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.

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

5. Computing the difference between the total unconstrained benefits and $482,742,672 (the total REP benefits adopted for the two-year rate period in the BP-18 7(i) proceeding).

6. 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 to only the IOU participants and the remainder is allocated to all participants on a pro rata basis referenced to unconstrained benefits.

7. Recomputing the IOU adjustments specified in Section 6.2 of the 2012 REP Settlement.

8. 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 Tables 2.4.11 and 2.4.12 of the Power Rates Study Documentation, BP-18-E-BPA-01A. Table 2.4.11 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 website.

U. 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-18 (including Slice purchasers), NR-18, and IP-18 rate schedules.

V. [Reserved for Future Use]

W. 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-18 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-18 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-18 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the PF-18 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.

X. 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-18 rate schedule may agree to a PF-18 Tier 1 Customer charge payment schedule for the rate period that differs from the flat monthly charge specified in the PF-18 rate schedule. BPA will, to the maximum extent practicable while ensuring timely BPA cost recovery, accommodate individual customer requests to "shape" certain PF-18 Tier 1 Customer charges within the fiscal year to mitigate adverse cash flow effects on the customer. The shaped payments at PF-18 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, 2017.

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.

Y. 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-18 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, 3, 4 and 5 of the NR-18 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, 3, 4 and 5 of the NR-18 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the NR-18 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.

Z. Cost Contributions

Pursuant to Section 7(j) of the Northwest Power Act (16 U.S.C. § 839e(j)), BPA has made the following resource cost determinations:

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

Table I
Resource Cost Contribution

Rate Schedule	*Federal Base System*	*Exchange Resources*	*New Resources*
PF	41.93%	58.07%	0%
IP	0%	49.17%	50.83%
NR	0%	51.99%	48.01%
FPS	0%	61.76%	38.24%

2. The cost of resources acquired to meet load growth within the region is estimated to be 41.41 mills/kWh, and the forecast average cost of resources available to BPA under average water conditions is 47.10 mills/kWh.

AA. 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	39.49	35.24	10.45
November	40.02	37.49	10.65
December	43.03	39.35	11.83
January	42.05	36.69	11.45
February	41.29	36.69	11.15
March	36.50	33.55	9.28
April	32.42	30.29	7.68
May	29.38	24.00	6.49
June	30.46	22.06	6.92
July	37.41	31.80	9.63
August	40.86	35.36	10.98
September	40.69	34.94	10.91

These rates are subject to adjustment during the Rate Period pursuant to the Spill Surcharge (GRSP Appendix C); the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Emergency NFB Surcharge (GRSP II.Q).

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-18), New Resources Firm Power (NR-18), and Firm Power and Surplus Products and Services (FPS-18) 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. **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.

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

   The Large Project Program, established in the BPA Revised Energy Efficiency Post-2011 Implementation Program, was discontinued on September 30, 2017.

9. **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.

10. **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.

11. New Resource Firm Power (NR)

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

(a) for any NLSL, as defined in the Northwest Power Act;

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

NR is to be used to meet the 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.

12. 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.

13. Priority Firm Power (PF)

Priority Firm Power (PF) is electric power (capacity and energy) that BPA will make continuously available for direct consumption or resale by public bodies, cooperatives, and Federal agencies. Utilities participating in the Residential Exchange Program 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.

14. 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). 16 U.S.C. § 839c(c). 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.

15. 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.

16. 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.

17. 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.

18. 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.

19. Transfer Service

As defined in the CHWM Contracts, Transfer Service means the transmission, distribution and other services provided by a third party transmission provider to deliver electric energy and capacity over its transmission system.

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 TRM, 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.H, 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. 16 U.S.C. § 839c(b).

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. Remarketing Value

The value BPA provides to customers for remarketed energy (both Tier 2 and non-Federal). This value is also used to calculate the cost of unpurchased amounts of Tier 2 energy. The Remarketing Value for a fiscal year is based on: (1) the rate case market price using the critical water year "augmentation price" when BPA has not yet acquired the power to supply Tier 2 service; (2) the weighted average price of the power purchases BPA has acquired (between October 1, 2016, and June 1, 2017) for the corresponding year to supply Tier 2 service; or (3) the average of the rate case market price using all 80 water years and the rate case market price using the critical water year "augmentation price" when BPA is using firm power from the FCRPS for Tier 2 service and BPA does not make any actual power acquisitions (between October 1, 2016, and June 1, 2017) for the corresponding year to supply Tier 2 service.

25. 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).

26. 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.

27. 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.

28. 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.A, Table A.

29. 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.

30. 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 2018–2019 are as follows (HE = Hour Ending):

October – May	HE 8 through HE 10 and HE 19 through HE 21
June – September	HE 14 through HE 19

31. 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.

32. 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 website.

33. 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.

34. 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.

35. 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.

36. 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.

37. 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.

APPENDICES

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Appendix A: Residential Exchange Program Settlement Customer Refund Amounts in FY 2018–2019

Section 1. Purpose

The Customer Refund Amount in FY 2018–2019 is a credit on a customer's power bill pursuant to the 2012 REP Settlement Agreement, REP-12-A-02A (misfiled as REP-12-A-02-AP01) (2012 REP Settlement). REP-12-A-02A. 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-18 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-18 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

BPA Customer ID Number	BP Customer Name	Customer Specific PF-02 Refund (1)	FY 2018 Scaled TOCA (2)	FY 2019 Scaled TOCA (2)	FY 2018 TOCA Refund	FY 2019 TOCA Refund	FY 2018 Total Refund	FY 2019 Total Refund
10005	Alder Mutual	$ 3,178	0.0079%	0.0079%	$ 3,035	$ 3,036	$ 6,213	$ 6,214
10015	Asotin County PUD #1	$ -	0.0084%	0.0084%	$ 3,221	$ 3,201	$ 3,221	$ 3,201
10024	Benton County PUD #1	$1,074,609	2.9560%	2.9381%	$1,131,209	$1,124,353	$2,205,818	$2,198,962
10025	Benton REA	$ 365,914	0.8762%	0.8708%	$ 335,292	$ 333,260	$ 701,206	$ 699,174
10027	Big Bend Elec Coop	$ 180,557	0.8987%	0.8932%	$ 343,916	$ 341,831	$ 524,473	$ 522,389
10029	Blachly Lane Elec Coop	$ 102,877	0.2587%	0.2571%	$ 99,002	$ 98,402	$ 201,879	$ 201,279
10044	Canby, City of	$ 146,793	0.2983%	0.2964%	$ 114,139	$ 113,447	$ 260,932	$ 260,240
10046	Central Electric Coop	$ 400,537	1.2021%	1.1948%	$ 460,010	$ 457,222	$ 860,547	$ 857,759
10047	Central Lincoln PUD	$ 483,285	2.2816%	2.2733%	$ 873,122	$ 869,959	$1,356,406	$1,353,244
10055	Albion, City of	$ -	0.0058%	0.0058%	$ 2,233	$ 2,224	$ 2,233	$ 2,224
10057	Ashland, City of	$ 161,518	0.3094%	0.3075%	$ 118,411	$ 117,693	$ 279,929	$ 279,212
10059	Bandon, City of	$ 55,554	0.1114%	0.1110%	$ 42,642	$ 42,486	$ 98,197	$ 98,041
10061	Blaine, City of	$ 60,506	0.1284%	0.1277%	$ 49,156	$ 48,858	$ 109,662	$ 109,364
10062	Bonners Ferry, City of	$ 45,589	0.0781%	0.0777%	$ 29,897	$ 29,716	$ 75,486	$ 75,305
10064	Burley, City of	$ 105,386	0.2065%	0.2053%	$ 79,041	$ 78,562	$ 184,427	$ 183,948
10065	Cascade Locks, City of	$ 17,913	0.0349%	0.0347%	$ 13,360	$ 13,279	$ 31,273	$ 31,192
10066	Centralia, City of	$ 164,230	0.3579%	0.3544%	$ 136,967	$ 135,605	$ 301,198	$ 299,835
10067	Cheney, City of	$ 108,606	0.2323%	0.2309%	$ 88,891	$ 88,352	$ 197,497	$ 196,958
10068	Chewelah, City of	$ -	0.0393%	0.0392%	$ 15,050	$ 14,994	$ 15,050	$ 14,994
10070	Declo, City of	$ -	0.0053%	0.0052%	$ 2,015	$ 2,003	$ 2,015	$ 2,003
10071	Drain, City of	$ 19,088	0.0279%	0.0278%	$ 10,663	$ 10,629	$ 29,751	$ 29,718
10072	Ellensburg, City of	$ 175,179	0.3522%	0.3501%	$ 134,782	$ 133,965	$ 309,961	$ 309,144
10074	Forest Grove, City of	$ 169,141	0.3919%	0.3895%	$ 149,958	$ 149,050	$ 319,099	$ 318,190
10076	Heyburn, City of	$ 50,558	0.0707%	0.0703%	$ 27,073	$ 26,909	$ 77,631	$ 77,467
10078	McCleary, City of	$ 35,576	0.0546%	0.0543%	$ 20,893	$ 20,766	$ 56,469	$ 56,342
10079	McMinnville, City of	$ 593,568	1.2950%	1.2871%	$ 495,572	$ 492,568	$1,089,140	$1,086,136
10080	Milton, Town of	$ 53,707	0.1092%	0.1086%	$ 41,797	$ 41,544	$ 95,505	$ 95,251
10081	Milton-Freewater, City of	$ 76,961	0.1447%	0.1438%	$ 55,376	$ 55,040	$ 132,337	$ 132,001
10082	Minidoka, City of	$ -	0.0015%	0.0015%	$ 575	$ 572	$ 575	$ 572
10083	Monmouth, City of	$ 59,603	0.1228%	0.1221%	$ 47,002	$ 46,717	$ 106,605	$ 106,320
10086	Plummer, City of	$ 28,254	0.0579%	0.0576%	$ 22,174	$ 22,040	$ 50,428	$ 50,293
10087	Port Angeles, City of	$ 517,172	0.4600%	0.4584%	$ 176,032	$ 175,406	$ 693,204	$ 692,579
10089	Richland, City of	$ 623,657	1.5252%	1.5160%	$ 583,685	$ 580,147	$1,207,342	$1,203,805
10091	Rupert, City of	$ 72,943	0.1384%	0.1375%	$ 52,952	$ 52,631	$ 125,895	$ 125,574
10094	Soda Springs, City of	$ -	0.0446%	0.0443%	$ 17,065	$ 16,961	$ 17,065	$ 16,961

BPA Customer ID Number	BP Customer Name	Customer Specific PF-02 Refund (1)	FY 2018 Scaled TOCA (2)	FY 2019 Scaled TOCA (2)	FY 2018 TOCA Refund	FY 2019 TOCA Refund	FY 2018 Total Refund	FY 2019 Total Refund
10095	Sumas, Town of	$ 23,429	0.0535%	0.0532%	$ 20,472	$ 20,348	$ 43,901	$ 43,777
10097	Troy, City of	$ -	0.0299%	0.0297%	$ 11,452	$ 11,383	$ 11,452	$ 11,383
10101	Clallam County PUD #1	$ 520,583	1.1165%	1.1098%	$ 427,285	$ 424,695	$ 947,868	$ 945,278
10103	Clark County PUD #1	$2,370,948	4.4577%	4.4446%	$1,705,886	$1,700,869	$4,076,834	$4,071,818
10105	Clatskanie PUD	$ 617,393	1.2615%	1.2354%	$ 482,763	$ 472,752	$1,100,156	$1,090,145
10106	Clearwater Power	$ 125,833	0.3507%	0.3486%	$ 134,203	$ 133,389	$ 260,036	$ 259,222
10109	Columbia Basin Elec Coop	$ -	0.1780%	0.1769%	$ 68,109	$ 67,696	$ 68,109	$ 67,696
10111	Columbia Power Coop	$ -	0.0440%	0.0436%	$ 16,851	$ 16,674	$ 16,851	$ 16,674
10112	Columbia River PUD	$ 265,444	0.8363%	0.8329%	$ 320,048	$ 318,727	$ 585,492	$ 584,172
10113	Columbia REA	$ -	0.5536%	0.5502%	$ 211,839	$ 210,556	$ 211,839	$ 210,556
10116	Consolidated Irrigation District #19	$ 1,825	0.0033%	0.0033%	$ 1,281	$ 1,273	$ 3,107	$ 3,099
10118	Consumers Power	$ 246,076	0.6708%	0.6667%	$ 256,691	$ 255,136	$ 502,767	$ 501,212
10121	Coos Curry Elec Coop	$ 229,267	0.5799%	0.5764%	$ 221,915	$ 220,570	$ 451,182	$ 449,837
10123	Cowlitz County PUD #1	$3,446,817	8.0655%	8.0166%	$3,086,555	$3,067,848	$6,533,372	$6,514,665
10136	Douglas Electric Cooperative	$ 105,338	0.2704%	0.2694%	$ 103,464	$ 103,090	$ 208,802	$ 208,428
10142	East End Mutual Electric	$ -	0.0395%	0.0392%	$ 15,101	$ 15,010	$ 15,101	$ 15,010
10144	Eatonville, City of	$ 23,238	0.0487%	0.0485%	$ 18,636	$ 18,558	$ 41,874	$ 41,796
10156	Elmhurst Mutual P & L	$ -	0.4720%	0.4706%	$ 180,621	$ 180,086	$ 180,621	$ 180,086
10157	Emerald PUD	$ 376,548	0.7337%	0.7292%	$ 280,769	$ 279,068	$ 657,317	$ 655,615
10158	Energy Northwest	$ 20,415	0.0394%	0.0391%	$ 15,062	$ 14,970	$ 35,476	$ 35,385
10170	Eugene Water & Electric Board	$1,490,101	3.5386%	3.5244%	$1,354,167	$1,348,720	$2,844,268	$2,838,821
10172	U.S. Airforce Base, Fairchild	$ 60,465	0.0824%	0.0823%	$ 31,547	$ 31,514	$ 92,013	$ 91,979
10173	Fall River Elec Coop	$ 152,407	0.4865%	0.4836%	$ 186,191	$ 185,062	$ 338,597	$ 337,469
10174	Farmers Elec Coop	$ -	0.0075%	0.0074%	$ 2,852	$ 2,835	$ 2,852	$ 2,835
10177	Ferry County PUD #1	$ 67,875	0.1475%	0.1411%	$ 56,431	$ 54,007	$ 124,306	$ 121,882
10179	Flathead Elec Coop	$ 608,080	2.4499%	2.4351%	$ 937,557	$ 931,875	$1,545,637	$1,539,955
10183	Franklin County PUD #1	$ 471,954	1.7234%	1.7130%	$ 659,525	$ 655,528	$1,131,479	$1,127,481
10186	Glacier Elec Coop	$ -	0.2735%	0.2735%	$ 104,678	$ 104,659	$ 104,678	$ 104,659
10190	Grant County PUD #2	$1,146,092	0.6011%	0.5974%	$ 230,019	$ 228,625	$1,376,111	$1,374,717
10191	Grays Harbor PUD #1	$ 736,828	1.9093%	1.8973%	$ 730,656	$ 726,055	$1,467,484	$1,462,882
10197	Harney Elec Coop	$ 91,382	0.3341%	0.3321%	$ 127,868	$ 127,093	$ 219,250	$ 218,475
10202	Hood River Elec Coop	$ 89,783	0.1924%	0.1912%	$ 73,615	$ 73,168	$ 163,398	$ 162,952
10203	Idaho County L & P	$ 39,010	0.0913%	0.0907%	$ 34,923	$ 34,711	$ 73,933	$ 73,721
10204	Idaho Falls Power	$ 435,271	0.9806%	0.9768%	$ 375,265	$ 373,795	$ 810,536	$ 809,066
10209	Inland P & L	$ -	1.5404%	1.5311%	$ 589,496	$ 585,923	$ 589,496	$ 585,923
10230	Kittitas County PUD #1	$ 48,061	0.1425%	0.1416%	$ 54,531	$ 54,200	$ 102,591	$ 102,261

BPA Customer ID Number	BP Customer Name	Customer Specific PF-02 Refund (1)	FY 2018 Scaled TOCA (2)	FY 2019 Scaled TOCA (2)	FY 2018 TOCA Refund	FY 2019 TOCA Refund	FY 2018 Total Refund	FY 2019 Total Refund
10231	Klickitat County PUD #1	$ 219,238	0.5384%	0.5351%	$ 206,028	$ 204,779	$ 425,266	$ 424,017
10234	Kootenai Electric Coop	$ -	0.7490%	0.7444%	$ 286,620	$ 284,883	$ 286,620	$ 284,883
10235	Lakeview L & P (WA)	$ 261,953	0.4641%	0.4636%	$ 177,618	$ 177,421	$ 439,571	$ 439,374
10236	Lane County Elec Coop	$ 154,159	0.4092%	0.4067%	$ 156,595	$ 155,646	$ 310,753	$ 309,804
10237	Lewis County PUD #1	$ 720,554	1.6201%	1.6144%	$ 619,977	$ 617,812	$1,340,531	$1,338,366
10239	Lincoln Elec Coop (MT)	$ -	0.2031%	0.2019%	$ 77,732	$ 77,261	$ 77,732	$ 77,261
10242	Lost River Elec Coop	$ 50,765	0.1379%	0.1381%	$ 52,754	$ 52,856	$ 103,518	$ 103,620
10244	Lower Valley Energy	$ -	1.2635%	1.2559%	$ 483,541	$ 480,610	$ 483,541	$ 480,610
10246	Mason County PUD #1	$ 52,092	0.1320%	0.1312%	$ 50,508	$ 50,202	$ 102,601	$ 102,295
10247	Mason County PUD #3	$ 544,117	1.1738%	1.1667%	$ 449,209	$ 446,486	$ 993,326	$ 990,603
10256	Midstate Elec Coop	$ 287,247	0.6673%	0.6635%	$ 255,374	$ 253,917	$ 542,621	$ 541,164
10258	Mission Valley	$ -	0.5574%	0.5540%	$ 213,295	$ 212,002	$ 213,295	$ 212,002
10259	Missoula Elec Coop	$ -	0.3963%	0.3939%	$ 151,660	$ 150,741	$ 151,660	$ 150,741
10260	Modern Elec Coop	$ -	0.3860%	0.3837%	$ 147,725	$ 146,830	$ 147,725	$ 146,830
10273	Nespelem Valley Elec Coop	$ 35,342	0.0864%	0.0859%	$ 33,055	$ 32,854	$ 68,396	$ 68,196
10278	Northern Lights	$ 134,905	0.4961%	0.4954%	$ 189,848	$ 189,592	$ 324,753	$ 324,497
10279	Northern Wasco County PUD	$ 169,186	0.9511%	0.9454%	$ 363,983	$ 361,777	$ 533,169	$ 530,963
10284	Ohop Mutual Light Company	$ -	0.1459%	0.1453%	$ 55,852	$ 55,620	$ 55,852	$ 55,620
10285	Okanogan County Elec Coop	$ 33,056	0.0959%	0.0953%	$ 36,692	$ 36,470	$ 69,748	$ 69,526
10286	Okanogan County PUD #1	$ 302,445	0.6742%	0.6702%	$ 258,024	$ 256,460	$ 560,469	$ 558,905
10288	Orcas P & L	$ -	0.3632%	0.3610%	$ 139,006	$ 138,164	$ 139,006	$ 138,164
10291	Oregon Trail Coop	$ 535,684	1.1553%	1.1558%	$ 442,136	$ 442,311	$ 977,820	$ 977,995
10294	Pacific County PUD #2	$ 263,432	0.5118%	0.5104%	$ 195,857	$ 195,321	$ 459,289	$ 458,753
10304	Parkland L & W	$ -	0.2030%	0.2023%	$ 77,669	$ 77,415	$ 77,669	$ 77,415
10306	Pend Oreille County PUD #1	$ 218,512	0.0000%	0.0000%	$ -	$ -	$ 218,512	$ 218,512
10307	Peninsula Light Company	$ 484,256	1.0039%	0.9990%	$ 384,178	$ 382,315	$ 868,434	$ 866,571
10326	U.S. Naval Base, Bremerton	$ 216,980	0.4277%	0.4251%	$ 163,671	$ 162,679	$ 380,652	$ 379,660
10331	Raft River Elec Coop	$ 81,677	0.5375%	0.5343%	$ 205,711	$ 204,464	$ 287,388	$ 286,141
10333	Ravalli County Elec Coop	$ -	0.2719%	0.2703%	$ 104,055	$ 103,425	$ 104,055	$ 103,425
10338	Riverside Elec Coop	$ -	0.0348%	0.0346%	$ 13,336	$ 13,255	$ 13,336	$ 13,255
10342	Salem Elec Coop	$ 342,469	0.5581%	0.5561%	$ 213,561	$ 212,803	$ 556,030	$ 555,272
10343	Salmon River Elec Coop	$ 126,695	0.1696%	0.1686%	$ 64,916	$ 64,522	$ 191,610	$ 191,217
10349	Seattle City Light	$2,806,762	7.6247%	7.6423%	$2,917,850	$2,924,594	$5,724,612	$5,731,357
10352	Skamania County PUD #1	$ 110,458	0.2276%	0.2266%	$ 87,094	$ 86,735	$ 197,552	$ 197,194
10354	Snohomish County PUD #1	$4,394,837	11.5548%	11.6241%	$4,421,849	$4,448,386	$8,816,686	$8,843,223

BPA Customer ID Number	BP Customer Name	Customer Specific PF-02 Refund (1)	FY 2018 Scaled TOCA (2)	FY 2019 Scaled TOCA (2)	FY 2018 TOCA Refund	FY 2019 TOCA Refund	FY 2018 Total Refund	FY 2019 Total Refund
10360	Southside Elec Lines	$ -	0.0994%	0.0988%	$ 38,025	$ 37,795	$ 38,025	$ 37,795
10363	Springfield Utility Board	$ 490,736	1.4088%	1.4038%	$ 539,123	$ 537,196	$1,029,859	$1,027,932
10369	Surprise Valley Elec Coop	$ 81,780	0.2413%	0.2399%	$ 92,350	$ 91,790	$ 174,129	$ 173,570
10370	Tacoma Public Utilities	$2,979,021	5.6095%	5.7383%	$2,146,689	$2,195,985	$5,125,710	$5,175,006
10371	Tanner Elec Coop	$ 59,409	0.1620%	0.1610%	$ 62,000	$ 61,624	$ 121,409	$ 121,034
10376	Tillamook PUD #1	$ 287,525	0.8096%	0.8067%	$ 309,834	$ 308,725	$ 597,359	$ 596,250
10378	Coulee Dam, City of	$ -	0.0281%	0.0281%	$ 10,754	$ 10,771	$ 10,754	$ 10,771
10379	Steilacoom, Town of	$ 35,527	0.0702%	0.0701%	$ 26,851	$ 26,826	$ 62,378	$ 62,353
10388	Umatilla Elec Coop	$ 557,880	1.6628%	1.6527%	$ 636,324	$ 632,467	$1,194,204	$1,190,347
10391	United Electric Coop	$ 144,156	0.4402%	0.4376%	$ 168,475	$ 167,454	$ 312,631	$ 311,610
10406	U.S. DOE Albany Research Center	$ 3,304	0.0067%	0.0067%	$ 2,574	$ 2,559	$ 5,879	$ 5,863
10408	U.S. Naval Station, Everett (Jim Creek)	$ 10,783	0.0215%	0.0214%	$ 8,243	$ 8,193	$ 19,026	$ 18,976
10409	U.S. Naval Submarine Base, Bangor	$ 151,547	0.2905%	0.2891%	$ 111,152	$ 110,632	$ 262,699	$ 262,179
10426	U.S. DOE Richland Operations Office	$ 193,387	0.2703%	0.4568%	$ 103,452	$ 174,823	$ 296,839	$ 368,210
10434	Vera Irrigation District	$ 190,495	0.3988%	0.3964%	$ 152,624	$ 151,699	$ 343,119	$ 342,194
10436	Vigilante Elec Coop	$ -	0.2813%	0.2796%	$ 107,637	$ 106,985	$ 107,637	$ 106,985
10440	Wahkiakum County PUD #1	$ 32,517	0.0733%	0.0728%	$ 28,045	$ 27,875	$ 60,562	$ 60,392
10442	Wasco Elec Coop	$ -	0.1948%	0.1942%	$ 74,539	$ 74,336	$ 74,539	$ 74,336
10446	Wells Rural Elec Coop	$ 388,509	1.4065%	1.3980%	$ 538,242	$ 534,980	$ 926,751	$ 923,489
10448	West Oregon Elec Coop	$ 48,959	0.1217%	0.1209%	$ 46,562	$ 46,279	$ 95,521	$ 95,239
10451	Whatcom County PUD #1	$ 179,980	0.3908%	0.3885%	$ 149,562	$ 148,655	$ 329,542	$ 328,636
10482	Umpqua Indian Utility Cooperative	$ 15,681	0.0405%	0.0402%	$ 15,486	$ 15,392	$ 31,167	$ 31,073
10502	Yakama Power	$ 7,897	0.2478%	0.2576%	$ 94,845	$ 98,583	$ 102,742	$ 106,480
10597	Hermiston, City of	$ 100,167	0.1857%	0.1845%	$ 71,048	$ 70,618	$ 171,215	$ 170,784
10706	Port of Seattle – SeaTac Int'l. Airport	$ -	0.2537%	0.2522%	$ 97,106	$ 96,517	$ 97,106	$ 96,517
11680	Weiser, City of	$ -	0.0929%	0.0924%	$ 35,566	$ 35,350	$ 35,566	$ 35,350
12026	Jefferson County PUD #1	$ -	NA	NA	$ -	$ -	$ -	$ -
13927	Kalispel Tribe Utility	$ -	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 2012 REP Settlement Agreement, REP-12-A-02A (misfiled as REP-12-A-02-AP01) (2012 REP Settlement). 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: Product Conversion Charge

Section 1. Purpose

Customers that converted from the Slice product to a non-Slice product beginning October 1, 2017, are subject to a customer-specific monthly charge. These customers received benefits associated with Regional Cooperation Debt management actions in FY 2014 and 2015 through the Slice True-Up for those years, while Non-Slice customers receive their share of FY 2014 and FY 2015 benefits in the PF-18 Tier 1 Non-Slice Customer charge. Application of this Product Conversion Charge avoids having the former Slice customers receive benefits twice.

Section 2. Product Conversion Charge

The monthly Product Conversion Charge for each customer is listed on the table below.

Customer Id	*Customer*	*FY 2018-2019 Monthly Charge*
10231	Klickitat PUD	$10,371
10349	Seattle City Light	$159,059

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Appendix C: Spill Surcharge

A. Availability

The Spill Surcharge applies to customers that purchase the following products under the PF rate: Load Following, Block, or the Block portion of Slice/Block. The Spill Surcharge also applies to power purchased at the PF Melded, IP, and NR rates.

B. Spill Surcharge Amount

The Spill Surcharge Amount is the total additional cost to be charged to customers in a Fiscal Year in which less Federal hydro generation is forecast to be available relative to the amount of Federal hydro generation forecast to be available in the BP-18 Final Proposal due to revised spill assumptions.

For each Fiscal Year of the rate period, the Spill Surcharge Amount shall be:

$$\left(\left(\frac{\left(\sum_{i=1}^{1120}\left((BP18FedGen_i - RevFedGen_i) \times BP18Price_i\right)\right)}{80}\right) - CostR\right) \times \left(1 - \sum Slice\%\right) - SecR$$

Where:

i = a single period for a particular water year. There are 14 periods per year (the months of April and August are split) and 80 water years, which results in an overall summation of 1,120 values. The monthly market price for April of a particular water year will be used twice, once for each split of April. The monthly market price for August of a particular water year will be used twice, once for each split of August.

BP18FedGen (BP-18 Final Proposal Federal Generation) is the Federal regulated hydro generation in average megawatts (aMW) from the BP-18 Final Proposal HYDSIM study, converted to megawatthours (MWh).

The 14 periods of generation for 80 water years for FY 2018 and FY 2019 are shown in the BP-18 Final Power Loads and Resources Study Documentation, BP-18-FS-BPA-03A.

RevFedGen (Revised Federal Generation) is the Federal regulated hydro generation in average megawatts (aMW) from the BP-18 Final Proposal HYDSIM study with revised planned spill assumptions, converted to megawatthours (MWh).

BP18Price (BP-18 Final Proposal Market Price) is the market price forecast from the BP-18 Final Proposal in $/MWh. The monthly market price forecast is shown in the Power Market Price Study and Documentation, BP-18-FS-BPA-04.

CostR (Cost Reductions) are specific forecast and actual program spending reductions determined by the Administrator that may be used to reduce the cost of the Spill Surcharge Amount. Cost Reductions are not mandatory and are subject to the discretion of the Administrator. The specified program spending reductions are relative to the program spending assumed for purposes of setting the BP-18 Final Proposal rates.

ΣSlice% is the sum of customer Slice percentages for the relevant Fiscal Year as specified in Exhibit K of the Slice customer's CHWM Contract.

SecR (Secondary Reduction) is equal to the net impact increased spill has on BPA's forecast balancing purchase costs and forecast revenue from remaining secondary sales due to any changes in the forecast market prices using BP-18 final studies with revised planned spill assumptions. Such amount will be reduced by any Spill Surcharge Amount that is not collected due to the application of the Low Density Discount. If the resulting *SecR* is less than zero, the *SecR* is deemed to be zero.

If the Spill Surcharge Amount calculation results in a value less than $5 million, the Spill Surcharge Amount is deemed to be zero.

C. Spill Surcharge Rate

The Spill Surcharge rate in mills per kilowatthour shall be:

$$\frac{\text{Spill Surcharge Amount}}{\sum \text{BD}}$$

Where:

$\sum$ *BD* (*Sum of Billing Determinants*) is the most current forecast of service under the PF Melded, IP, and NR rates and the sum of the PF System Shaped Loads for the unbilled remaining portion of the applicable Fiscal Year, in kilowatthours.

D. Billing

For customers taking service at the PF Melded, IP, and NR rates, the Spill Surcharge rate will be added to each of the remaining monthly/diurnal PF Melded, IP and NR energy rates for the applicable Fiscal Year.

For PF customers with a System Shaped Load, the Spill Surcharge rate will be applied to the sum of each customer's HLH and LLH PF System Shaped Load for the remaining months of the applicable Fiscal Year. A customer's Low Density Discount shall be applied to the Spill Surcharge.

For any FY 2018 Spill Surcharge, a PF customer with a System Shaped Load may request a payment schedule of flat monthly amounts that recover its FY 2018 Spill Surcharge over the remaining months in the rate period. BPA will accommodate such requests if, in BPA's sole determination, there are no material adverse impacts on BPA's cash flow, including material increases in the forecast likelihood of triggering the Power Cost Recovery Adjustment Clause (GRSP II.O).

E. Annual Spill Surcharge Rate and Other Adjustments

1. Annual Spill Surcharge Rate

An Annual Spill Surcharge Rate, in mills per kilowatthour, will be calculated so that the Load Shaping Charge True-up rate and PF Melded Equivalent Energy Scalar can be adjusted. The Annual Spill Surcharge Rate is calculated by dividing the Spill Surcharge Amount by the annual forecast, in kilowatthours, made around the beginning of each Fiscal Year of service under the PF Melded, IP, and NR rates and the sum of the PF System Shaped Loads for the applicable year. The Annual Spill Surcharge Rate will be:

a. Subtracted from the Load Shaping Charge True-Up rate (GRSP II.E, Section 1)

b. Subtracted from the PF Melded Equivalent Energy Scalar rate (GRSP II.R, Section 1(c)).

2. Adjustment to the PF Tier 1 Equivalent Energy Rates

The Spill Surcharge Rate (Section C, above) will be added to each of the monthly/diurnal PF Tier 1 Equivalent energy rates (GRSP II.AA) for the remaining months of the applicable Fiscal Year.

F. Notification

For each year of the rate period, BPA will notify customers of the preliminary Spill Surcharge Amount to be recovered by the Spill Surcharge for the fiscal year (if any). Such notice will be provided as soon as practicable, but in no case later than May 31 of each Fiscal Year. BPA will make available to customers the preliminary data and

assumptions relied upon to calculate the surcharge including any proposed program spending reductions.

BPA will hold at least one public meeting to review the calculation of the Spill Surcharge Amount, Spill Surcharge Rate, and the Annual Spill Surcharge Rate. BPA will provide at least 10 business days for comment on the preliminary data and assumptions. No later than 14 calendar days after the comment period closes, BPA will issue the final Spill Surcharge Amount, Spill Surcharge Rate, and the Annual Spill Surcharge Rate, and apply such rates in the next available billing cycle. See GRSP Appendix D, Supplemental Information, for applicable FY 2018 and FY 2019 Spill Surcharges.

Appendix D

Supplemental Information

Adjustments to rates and GRSPs during the Rate Period due to the Power CRAC (GRSP II.O), the Power RDC (GRSP II.P), the Emergency NFB Surcharge (GRSP II.Q), and the Spill Surcharge (GRSP Appendix C) are summarized here.

I. Spill Surcharge for Fiscal Year 2018

Spill Surcharge Rate	**0.71 mills/kWh for the months of June – September, 2018**
Annual Spill Surcharge Rate	**0.23 mills/kWh**

A. Spill Surcharge for Rate Schedules

Rate Schedule/Service	**For June – September 2018 service, the Spill Surcharge Rate of 0.71 mills/kWh shall be applied to the following billing determinants:**
PF (Section 2.1.5) • Load Following • Block • Block portion of Slice/Block	System Shaped Load for HLH and LLH
PF Melded Rate (Section 3)	Total hourly energy loads for each diurnal period
NR (Section 2.1.1.2)	Total of NR Hourly Loads for each diurnal period
IP (Section 2.1.1.3)	Energy Entitlement

B. GRSP Factors Adjusted by Annual Spill Surcharge Rate (0.23 mills/kWh)

GRSP	**Adjusted factors for FY 2018**
GRSP II.E, Load Shaping Charge True-Up Adjustment, Section 1	Load Shaping True-Up Rate = -12.98 mills/kWh
GRSP II.R, Slice True-Up Adjustment, Section 1(c)	PF Melded Equivalent Energy Scalar (PFMEES) Rate = -12.89 mills/kWh

C. GRSP II.AA. Priority Firm Power (PF) Tier 1 Equivalent Energy Rates for FY 2018 Adjusted by Spill Surcharge Rate[1/]

FY 2018	***Energy Rate in mills/kWh***	
	HLH	***LLH***
June	31.17	22.77
July	38.12	32.51
August	41.57	36.07
September	41.40	35.65

1/Spill Surcharge Rate of 0.71 mills/kWh is added to June – September, 2018, energy rates (shown in chart). All other PF Tier 1 Equivalent rates (energy and demand) remain the same.

BONNEVILLE POWER ADMINISTRATION
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