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

BP-16 Rate Proceeding

Power Rates Study

BP-16-FS-BPA-01

July 2015

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COMMONLY USED ACRONYMS AND SHORT FORMS

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

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

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

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

1. INTRODUCTION AND BACKGROUND

1.1 Power Rates Study Overview

The Power Rates Study (PRS) explains the processes and calculations used to develop the power rates and billing determinants for Bonneville Power Administration's (BPA) wholesale power products and services. The PRS serves three primary purposes: (1) to demonstrate that the rates have been developed in a manner consistent with statutory direction, including the initial allocation of costs and the subsequent reallocations directed by statute; (2) to set rates consistent with BPA's agency policy; and (3) to demonstrate that the rates have been set at a level that recovers the allocated power revenue requirement for the upcoming rate period.

The development of rates in the PRS uses inputs from a variety of sources:

- Loads and resources are provided by the Power Loads and Resources Study, BP-16-FS-BPA-03, and its accompanying documentation, BP-16-FS-BPA-03A.
- Power revenue requirement information is provided by the Power Revenue Requirement Study, BP-16-FS-BPA-02, and its accompanying documentation, BP-16-FS-BPA-02A; *see* Power Revenue Requirement Study § 2.5.
- The Power Risk and Market Price Study, BP-16-FS-BPA-04, and its accompanying documentation, BP-16-FS-BPA-04A, provide the study with the electricity market price forecasts and forecast quantities of power expected to be sold and purchased in electric markets. The market price forecasts are used in the development of the demand rates, load shaping rates, short-term balancing purchases and expenses, augmentation purchases and expenses, secondary energy sales and revenue, and Planned Net Revenues for Risk (PNRR), if any.

Power Services receives revenue from the generation inputs it provides to Transmission Services. The amount of the generation inputs revenue credit is specified in the BP-16 Generation Inputs and Transmission Ancillary and Control Area Services Rates Partial Settlement Agreement. *See* BP-16 Final Record of Decision, BP-16-A-02, Appendix A, at 57.

The results of the power rate development process, including rates and billing determinants for power products and services and general rate schedule provisions, appear in the power rate schedules. The revenues resulting from the rates developed herein are used by the Power Revenue Requirement Study in the Revised Revenue Test to test the adequacy of the rates to recover expenses and supply adequate cash to cover non-expense cash outlays. *See* Power Revenue Requirement Study, BP-16-E-BPA-02, § 3.3.

1.2 Statutory and Legal Overview

The Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839 (2015), is the primary statute providing ratemaking directives to BPA. Section 7(a)(1) states:

> The Administrator shall establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Such rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator pursuant to this chapter and other provisions of law.

The Bonneville Project Act defines "periodically review and revise" as revision of power and transmission rates not less frequently than once in every five years. 16 U.S.C. § 832d(a) (2015). Rates also are to be set in accordance with two other statutes, the Federal Columbia River Transmission System Act (Transmission System Act), 16 U.S.C. § 838 (2015), and the Flood Control Act of 1944, 16 U.S.C. § 825s (2015).

Section 7 of the Northwest Power Act governs the allocation of BPA's costs, which is performed in a cost of service analysis (section 2.1), and establishes a set of rate directives that provide further guidance on how individual rates are to be derived (section 2.2).

1.3 Regional Dialogue Policy Overview

In the Long-Term Regional Dialogue Policy, issued in July 2007, BPA defined its power supply and marketing role for the long term. Key components of the policy include 20-year power sales contracts and a tiered Priority Firm Power (PF) rate construct that provides each preference customer with a Contract High Water Mark (CHWM). Each customer's CHWM defines the amount of power that customer has a right to buy at a Tier 1 rate. Any power a utility chooses to buy from BPA for its load in excess of its CHWM is priced at a Tier 2 rate that is designed to recover the marginal cost of serving this additional load.

In October 2008, BPA offered Regional Dialogue contracts to all of its preference and investor-owned utility (IOU) customers. By December 5, 2008, all preference customers and three of seven IOUs signed the new contracts, which went into effect immediately. Power service under these contracts commenced at the start of fiscal year (FY) 2012. The other four IOUs have since signed Regional Dialogue contracts also.

1.3.1 Regional Dialogue Contract Product Descriptions

Below is a brief summary of the products offered under BPA's CHWM contracts. Please refer to BPA's *Regional Dialogue Guidebook*, available in the Regional Dialogue Policy Implementation section of BPA's Web site, www.bpa.gov, for full product descriptions and additional details on the interactions of the products, Tier 2 rate service, and Resource Support Services (RSS).

Load Following. The Load Following product supplies firm power to meet a preference customer's Total Retail Load (TRL), less any firm power supplied by the customer from any Dedicated Resources, including "behind the meter" non-Federal resource amounts. The costs associated with the energy and capacity necessary to provide the Load Following service are recovered through Tier 1 rate charges for energy and demand.

Block. The Block product provides a planned amount of firm power to meet a preference customer's planned annual net requirement load. To buy this product, the customer must have dedicated non-Federal resources, and the customer is responsible for using those resources dedicated to its TRL to meet any load in excess of its planned monthly BPA Block purchase. The costs associated with the energy and capacity necessary to provide this service are recovered through Tier 1 rate charges for energy and demand. Currently, one customer has elected to purchase the Block-only product.

Slice/Block. The Slice/Block product provides a combined sale of two distinct power products: (1) firm power for a preference customer's net requirements load and an advance sale of surplus energy based on the generation shape of the Federal system; and (2) firm requirements power under a Block product. The costs associated with the energy and capacity necessary to provide this service are recovered through Tier 1 rate charges for energy and demand.

1.4 Tiered Rate Methodology

In November 2008, BPA issued its Tiered Rate Methodology (TRM). Together, the CHWM contracts and the TRM provide long-term certainty to preference customers regarding their access to Tier 1 rate power and to BPA regarding its obligation to serve its preference customers' loads. The TRM was revised in the BP-12 rate proceeding. *See* 2012 Wholesale Power and Transmission Rate Adjustment Proceeding (BP-12), Tiered Rate Methodology, BP-12-A-03.

The TRM provides for a two-tiered PF Public rate design applicable to firm requirements power service for preference customers that signed CHWM contracts. The TRM established a predictable and durable means to calculate BPA's PF tiered rates for power deliveries beginning in FY 2012. The tiered rate design differentiates between the cost of service associated with Tier 1 system resources and the cost associated with additional amounts of power sold by BPA to serve any remaining portion of a customer's net requirement, also referred to as Above-Rate Period High Water Mark (Above-RHWM) load. The tiering of the PF Public rate is one of the final steps in the development of rates and does not alter the fundamental manner in which BPA allocates costs to the various rate pools under the Northwest Power Act. PRS section 2.3.2 describes the steps taken to tier the PF Public rate.

CHWMs, determined according to the TRM, help determine how much of each customer's net requirement purchased from BPA is charged at Tier 1 rates and how much may be charged at Tier 2 rates. The CHWM for each customer was calculated by BPA in FY 2011 based on the expected output of Tier 1 system resources during FY 2012–2013 and customers' actual FY 2010 loads. The individual utility CHWMs set each customer's initial eligibility to purchase power at Tier 1 rates and were inserted in each utility's CHWM contract.

1.4.1 Rate Period High Water Marks

Related to the CHWM and also defined in the TRM is the RHWM, which is an expression of the CHWM scaled to the expected output of resources identified as comprising the Tier 1 system for the relevant rate period. Each customer's RHWM for FY 2016–2017 defines that customer's maximum eligibility to purchase at Tier 1 rates for the rate period, limited for Slice and Block customers by the purchaser's Annual Net Requirement and for Load-Following customers by the purchaser's Actual Net Requirement. The TRM specifies how rates will be developed to ensure, to the maximum extent possible, that customers' purchases of power at Tier 1 rates do not pay any of the costs of serving Above-RHWM load.

To meet its Above-RHWM load, a customer may purchase Federal power, non-Federal power, or a combination of the two. To the extent a customer purchases Federal power for its Above-RHWM load, a PF Tier 2 rate(s) will be applied to this portion of its Federal power service; *see* § 3.1.9.

1.4.2 Rate Period High Water Mark Process

The RHWM is determined based on the customer's CHWM and the RHWM Tier 1 System Capability (RT1SC) for each applicable rate period. The determination of a customer's RHWM occurs outside of the rate proceeding in the RHWM Process, as described in TRM § 4.2.1.

The RHWM Process for the FY 2016–2017 rate period was completed in October 2014. BPA completed the Tier 1 System Firm Critical Output (T1SFCO) Study and posted draft RHWM amounts in August 2014. BPA engaged customers in a public process spanning three months, three public comment periods, and three public workshops. After completion of the review and comment period, BPA examined the information collected. The outcome of the extensive review process was an increase in the T1SFCO of 38 aMW from the initial August 2014 amount. BPA posted its determination of values for the FY 2016–2017 rate period for RHWM Tier 1 System Capability, including RHWM Augmentation, the monthly/diurnal shape of RHWM Tier 1 System Capability, and each customer's RHWM, Forecast Net Requirement, and Above-RHWM Load. *See* Study Table 1.

Once established, RHWMs are, under most circumstances, not changed. Exceptions include certain changes on a customer's system: annexation; gaining or losing service territory; or later discovery that a load is a new large single load.

1.5 Residential Exchange Program

On July 26, 2011, the Administrator executed the 2012 REP Settlement, which resolved longstanding litigation over BPA's implementation of the Residential Exchange Program (REP) under section 5(c) of the Northwest Power Act, 16 U.S.C. § 839c(c). The 2012 REP Settlement and the Administrator's decision in the REP-12 ROD to sign the settlement were upheld by Ninth Circuit Court of Appeals in *Ass'n of Pub. Agency Customers v. Bonneville Power Admin.*, 733 F.3d 939 (9th Cir. 2013).

BPA is implementing the 2012 REP Settlement in rates for FY 2016–2017. The 2012 REP Settlement establishes a fixed stream of REP benefits that are payable to the IOUs beginning in FY 2012 and ending in FY 2028. For the two consumer-owned utilities (COUs) currently participating in the REP, BPA compares their respective ASCs with the COU PF Exchange rates (established pursuant to separate settlements with each COU) and, if the difference is positive, multiplies the difference by their exchange loads to determine their REP benefits. The COUs' REP benefits are in addition to the fixed stream of IOU REP benefits under the 2012 REP Settlement.

The participating utilities' average system costs (ASCs) are determined outside the rate proceeding in an ASC Review Process that BPA conducts pursuant to the substantive and procedural requirements of the 2008 ASC Methodology (ASCM). *See* ASCM, 18 C.F.R. § 301 *et seq.* (2008). The Federal Energy Regulatory Commission granted final approval to the 2008 ASCM on September 4, 2009. *See* PRS Chapter 8.

2. RATESETTING METHODOLOGY AND PROCESS

BPA's ratesetting process for power products and services under the Regional Dialogue contracts has three main steps:

(1) A Cost of Service Analysis (COSA) Step (section 2.1), which allocates the various types of costs (categorized into resource or cost pools) to the various classes of customers (categorized into load or rate pools) using allocation factors calculated based on loads and resources.

(2) A Rate Directives Step (section 2.2), which reallocates costs between rate pools to ensure that the relationships between the rates for the different classes of customers comport with the rate directives in the Northwest Power Act.

(3) A Rate Design Step (section 2.3), which produces tiered PF Public (PFp) rates that collect the PFp revenue requirement determined in the Rate Directives Step. This step also implements the rate design for the other non-tiered rates, IP and NR.

2.1 Cost of Service Analysis Step

2.1.1 Introduction

Northwest Power Act sections 7(b), 7(f), and 7(g) provide guidance to BPA for allocating resource and other costs to load (rate) pools, which is performed in the Rate Analysis Model (RAM2016).

Section 7(b)(1) states:

> The Administrator shall establish a rate or rates of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the Pacific Northwest, and loads of electric utilities under section 5(c) of this title. Such rate or rates shall recover the costs of

> that portion of the Federal base system resources needed to supply such loads until such sales exceed the Federal base system resources. Thereafter, such rate or rates shall recover the cost of additional electric power as needed to supply such loads, first from the electric power acquired by the Administrator under section 5(c) of this title and then from other resources.

Section 7(b)(1) thus describes how BPA is to allocate resource costs to meet the general requirements of public body, cooperative, and Federal agency customers within the Pacific Northwest and loads of electric utilities participating in the Residential Exchange Program (REP) under section 5(c), collectively called the Priority Firm Power (PF) customer class. At this initial stage of the ratesetting process, the PF rate pool consists of the loads of public bodies and cooperatives (collectively identified as preference customers in Northwest Power Act section 5(b)), which are combined with Federal agency loads in section 7(b)(1), and the loads of the REP-participating utilities.

Section 7(b)(1) requires that Federal base system (FBS) resources be used to serve the PF rate pool until the FBS resources are exhausted. Thus, a corresponding amount of FBS costs is allocated to the PF rate pool. After FBS resources are fully used, resources acquired pursuant to the REP (called exchange resources) are used, and then, if needed, new resources are used to serve remaining PF rate load. By allocating resource costs in this order, the appropriate amounts of exchange and new resource costs are allocated to the PF rate pool.

Section 7(f) states:

> Rates for all other firm power sold by the Administrator for use in the Pacific Northwest shall be based upon the cost of the portions of Federal base system resources, purchases of power under section 5(c) of this title and additional

resources which, in the determination of the Administrator, are applicable to such sales.

Section 7(f) sets forth how costs are allocated to rates for all other firm power after costs are allocated to the PF rate pool and the rates for BPA's direct-service industrial customers (DSIs) are determined. Section 7(f) allocates the remaining exchange and new resource costs to the remaining regional load (power sold at the New Resources Firm Power (NR) rate and the Firm Power and Surplus Products and Services (FPS) rate).

Section 7(g) states:

> Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on December 5, 1980, or by other provisions of this section, the Administrator shall equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this chapter, all costs and benefits not otherwise allocated under this section, including, but not limited to, conservation, fish and wildlife measures, uncontrollable events, reserves, the excess costs of experimental resources acquired under section 6 of this title, the cost of credits granted pursuant to section 6 of this title, operating services, and the sale of or inability to sell excess electric power.

Section 7(g) thus addresses the allocation of costs that are not covered by the previously cited sections of the Northwest Power Act, such as conservation and fish and wildlife costs.

Consistent with these mandates, the COSA assigns repayment responsibility for ("allocates") BPA's power revenue requirement (grouped into resource pools, or "cost pools") to the various classes of service (grouped into load pools, or "rate pools"). These allocations are based upon the resources used to serve those loads, in compliance with the statutory directives governing BPA's ratemaking and in accordance with generally accepted ratemaking principles. The COSA and the other ratemaking steps are programmed into the RAM2016 spreadsheet model for purposes of calculating power rates.

2.1.2 Cost of Service Analysis Modeling Summary

The COSA modeling uses disaggregated customer load data from the source data used to produce the Power Loads and Resources Study, BP-16-FS-BPA-03. *See* PRS Documentation Table 2.1.1. The disaggregated load data are aggregated into the PF rate pool (consisting of two sub-pools, the PF Public (PFp) rate pool, and the PF Exchange (PFx) rate pool); the Industrial Firm Power (IP) rate pool; the NR rate pool; and the FPS rate pool. *See* Documentation Table 2.2.2.

After the load data are input into the RAM2016, the COSA modeling uses the disaggregated resource data from the source data in the Power Loads and Resources Study. *See* Documentation Table 2.1.2. The disaggregated resource data are aggregated into the resource pools specified by section 7 of the Northwest Power Act. These resource pools are the FBS resource pool, the exchange resource pool, and the new resource pool. *See* Documentation Table 2.2.2. The resources in the FBS and new resource pools are actual or planned resources that will be able to serve actual load during the rate period. The exchange resources are sized to be equal to the forecast of the eligible REP exchange load during the rate period. To calculate the eligible REP exchange load, the COSA modeling includes a test that determines whether the potential exchanging utilities have Average System Costs (ASC) that are greater than the applicable Base PFx rate for the rate period. *See* section 2.2.2.2 below. Those utilities with higher ASCs are included in the REP exchange during the rate period. *See* Documentation Table 2.1.3. In this way, the modeling determines the PFx load, the size of the exchange resource pool, and the costs of the exchange resources (the ASCs multiplied by the eligible exchange loads).

The aggregated load and resource data are used to calculate energy allocation factors (EAFs) that the COSA modeling will use to apportion costs among rate pools. In order to properly calculate EAFs, loads and resources must equal one another; the RAM2016 tests to ensure that this load-resource balance exists. The EAFs are calculated based on the priorities of service from resource pools to rate pools specified in section 7 of the Northwest Power Act, and based on general principles of cost causation when section 7 does not provide guidance.

Section 7(b)(1) directs BPA to allocate the cost of the FBS resources to the PF load pool first. When the FBS resources are not sufficient to serve all PFp and PFx loads, section 7(b)(1) directs BPA to serve the remaining load first with exchange resources obtained by BPA under section 5(c) of the Northwest Power Act and then with new resources, as needed. For the BP-16 rates, all of the FBS and a large portion of exchange resources are needed to serve PF loads, and no new resources are needed. After all of the FBS resource costs and the portion of the exchange resource costs are allocated to the PF rate pool, section 7(f) of the Act directs BPA to allocate the cost of the remaining exchange resources and the cost of any other resources, new resources, to all remaining load.

The COSA modeling uses revenue requirement cost data from the Power Revenue Requirement Study, BP-16-FS-BPA-02. *See* PRS Documentation Table 2.3.1. The disaggregated cost data are aggregated into BPA's ratemaking cost pools specified by section 7 of the Northwest Power Act. *See* Documentation Table 2.3.2. Sections 7(b) and 7(f) describe how costs associated with resource pools (FBS costs, exchange resource costs, and new resource costs) are to be allocated to load/rate pools. Section 7(g) describes how the costs associated with the other cost pools (conservation costs, BPA program costs, power-related transmission costs) are to be allocated to load/rate pools.

Functionalization of costs between the generation and transmission functions (BPA does not have a distribution function normal to most utilities) is performed in the Power Revenue Requirement Study and the Transmission Revenue Requirement Study. The costs functionalized to the generation function are included in the power revenue requirement found in the COSA modeling (one exception is exchange resource costs; *see* § 2.1.4.2). As stated above, the exchange resource costs are calculated internal to the RAM2016. The exchange resource costs include transmission function costs. The exchange resource costs are functionalized in the COSA modeling so that only the generation portion of the exchange resource costs is subject to the power cost rate steps, and the transmission cost portion is then added back in after the Rate Directives Step is completed. *See* Documentation Table 2.3.4.2. In this way, the statutorily mandated power cost relationships between the various rate pools are maintained without being affected by the exchange transmission function costs.

The COSA modeling uses other costs in addition to exchange resource costs that are internally generated by the RAM2016. These include some power purchase costs, revenue shortfall costs associated with some rate credits, and revenues from secondary power sales. These items will be covered in greater detail below.

In addition to cost data, the COSA modeling receives input data associated with various revenue credits. Some of these revenue credits are associated with the operation of FBS resources and have the effect of reducing the FBS resource costs to be recovered by power rates. There are also revenue credits that have the effect of reducing the new resource and conservation costs.

Some revenue credits that are not associated with any particular cost pool are allocated to all rate pools on a pro rata load basis. *See* Documentation Table 2.3.6.

The COSA modeling concludes by using the calculated EAFs to allocate these remaining costs and credits to the rate pools. One further adjustment to the allocated costs is necessary because the costs allocated to the FPS rate pool will not be equal to the expected revenues from FPS contract sales. Therefore, an FPS surplus/deficiency adjustment to the COSA allocated costs is performed before the calculation of initial power rates. *See* Documentation Table 2.3.9. The initial power rates resulting from the COSA Step are the starting point for the Rate Directives Step modeling in the RAM2016. *See* Documentation Table 2.3.10.

Sections 2.1.3, 2.1.4, and 2.1.5 below provide more detailed explanations of the material summarized here.

2.1.3 Loads and Resources

The COSA modeling uses disaggregated customer load data from the source data used to produce the Power Loads and Resources Study, BP-16-FS-BPA-03. *See* Documentation Table 2.1.1. The disaggregated load data are aggregated into the PF rate pool (consisting of two sub-pools, the PF Public (PFp) rate pool and the PF Exchange (PFx) rate pool); the Industrial Firm Power (IP) rate pool; the NR rate pool; and the FPS rate pool. *See* Documentation Table 2.2.2. The rates charged for service to the various rate pools are associated with specific sections in the Northwest Power Act that describe how costs are to be allocated to those rate pools: the PF rates are section 7(b) rates; the IP rates are section 7(c) rates; and the NR and FPS rates are section 7(f) rates.

The COSA modeling also uses the disaggregated resource data from the source data in the Power Loads and Resources Study. *See* Documentation Tables 2.1.2.1 and 2.1.2.2. The disaggregated resource data are aggregated into the resource pools specified by section 7 of the Northwest Power Act. These resource pools are the FBS resource pool, the exchange resource pool, and the new resource pool. *See* Documentation Table 2.2.2. The resources in the FBS and new resource pools are actual or planned resources that will be able to serve actual load during the rate period. The ratemaking process requires that the forecast of firm resources available to serve load is equal to BPA's firm load obligations under critical water conditions. Critical water conditions assume very low streamflow along with today's generating facilities and constraints to yield an amount of energy output.

2.1.3.1 Load Pools

Load pools (also called rate pools) are groupings of forecast sales into customer classes for cost allocation purposes. The Northwest Power Act establishes three rate pools based on the loads served at particular rates. The 7(b) rate pool includes sales to public body and cooperative customers (consumer-owned utilities or COUs), Federal agencies, and utilities participating in the REP. The 7(c) rate pool includes sales to BPA's DSI customers under contracts authorized by section 5(d) of the Northwest Power Act. The 7(f) rate pool includes three types of sales: (1) power sold to consumer-owned utilities that is determined to serve new large single loads (NLSLs); (2) section 5(b) requirements power sold to the region's IOUs; and (3) all power BPA sells pursuant to section 5(f) of the Northwest Power Act.

The Northwest Power Act states that after July 1, 1985, BPA is not required to allocate any resource costs to the IP rate pool; rather, the IP rate is set using a formula pursuant to section 7(c). The formula ties the IP rate to the PF rate. However, if DSI loads were excluded from cost allocations, loads and resources would be out of balance, leaving an amount of resource costs not allocated to any loads. Therefore, for ratemaking purposes BPA allocates resource costs to IP loads as it does to all other remaining firm power sold. The result is that BPA has, for all practical purposes, only two rate pools, the 7(b) rate pool and all other loads. The resource cost allocations to the IP rate pool are adjusted later in the Rate Directives Step to conform the IP rate to the statute-based formula.

2.1.3.2 Resource Pools

The three resource pools are Federal base system resources, exchange resources, and new resources.

Defined in section 3(10) of the Northwest Power Act, the FBS resource pool consists of the costs of the following resources: (1) the Federal Columbia River Power System (FCRPS) hydroelectric projects; (2) resources acquired by the Administrator under long-term contracts in force on the effective date of the Northwest Power Act; and (3) replacements for reductions in the capability of the above resources. Market purchases of system augmentation, balancing purchases, and purchases designated for Tier 2 rate purposes have been included in the FBS as replacements for reductions in the capability of FBS resources. Costs expected to be incurred during the rate period for FBS replacement resources are included in the FBS resource cost pool.

To implement the direction in section 5(c)(1) that BPA is to purchase resources from each eligible REP participant and sell an equivalent amount of electric power to each participant, the exchange resources are sized to be equal to the forecast of the eligible REP exchange load during the rate period. To calculate the eligible REP exchange load, the COSA modeling includes a test that determines whether the potential exchanging utilities have ASCs that are greater than the applicable Base PF Exchange rate for the rate period. Utilities with ASCs higher than the Base PFx rate are assumed to participate in the REP during the rate period. In this way, the modeling estimates the PFx load, the size of the exchange resource pool, and the costs of the exchange resources (the ASCs multiplied by the eligible exchange loads). *See* Documentation Table 2.1.3. This process is iterative and dependent upon the outcomes of the Rate Directives Step. *See* sections 2.2.2.2 and 2.4.1.1.

Exchange resources are set equal to the amount of qualifying exchange load, which implements the direction in section 5(c)(1) that BPA is to purchase resources from each eligible REP participant and sell an equivalent amount of electric power to each participant.

Finally, the new resources pool includes all other resources acquired by BPA, unless such resource has been determined to be a replacement for reduced FBS capability.

2.1.3.3 Order of Resource Service to Load Pools

Section 7(b)(1) of the Northwest Power Act specifies how resource costs must be allocated to the Priority Firm Power customer class. FBS resources are used to serve the PF rate pool until FBS resources are exhausted, whereupon exchange resources and then new resources are used to serve remaining PF rate load. Section 7(f) of the Northwest Power Act specifies what and how costs are allocated to “all other firm power” after costs are allocated to the PF rate pool; the remaining exchange and new resources costs are allocated to remaining load. That remaining load is Industrial Firm Power, New Resource Firm Power, and Firm Power and Surplus Products and Services contracts.

For the BP-16 rates, the PF load (which includes both PFp and PFx loads) is greater than the capability of the FBS resources. Therefore, all FBS costs and benefits are allocated to the PF rate pool. A pro rata share of exchange resource costs is allocated to the PF rate pool in the amount necessary for the exchange resources to serve the PF load not served by FBS resources.

The costs of remaining exchange resources and all new resources are allocated to all other firm load.

2.1.3.4 Load and Resource Adjustments

The Power Loads and Resources Study includes a forecast of the generation capability of all resources available to BPA to serve all of its load obligations. Ratemaking uses only the amount of resources available to serve the rate pool loads; thus, some adjustments must be made. BPA has certain system obligations, including the Canadian Entitlement, the Hungry Horse reservation, and U.S. Bureau of Reclamation (USBR) Pumping loads (together called FBS obligations), that have existed since before the passage of the Northwest Power Act. FBS resources used to serve these system obligations are "taken off the top," removing both the obligation and a corresponding amount of FBS resource before the ratemaking load-resource balance is calculated.

Similarly, there is an amount of the FBS used to serve a group of power contracts that enhances the amount of FBS available to serve the rate pools. These contracts take the form of either a capacity-energy exchange or a seasonal exchange. Each of these types of exchanges is a "sale" of power that is paid for by returning more power than is delivered. In ratemaking, the deliveries and the equivalent returns are removed from consideration, and the energy payment is included in the FBS, increasing the net size of the FBS with power at no added cost. The ratemaking load-resource balance after adjustments is shown in Documentation Table 2.2.2.

2.1.3.5 Energy Allocation Factors

The aggregated load and resource data are used to calculate energy allocation factors that the COSA modeling will use to apportion costs amoung rate pools. EAFs are calculated for each resource pool–rate pool combination by dividing the amount of annual energy load in each rate pool by the amount served from each resource pool. The annual EAFs for each resource cost pool and for the rate directive steps are shown in Documentation Tables 2.2.3.1 and 2.2.3.2. The General and Conservation allocation factors assume a pro rata allocation of costs to all firm loads. For example, the General and Conservation EAFs are used to allocate some section 7(g) costs and rate directive allocation adjustments to all firm energy loads.

2.1.4 Ratemaking Costs

The COSA modeling uses revenue requirement cost data from the Power Revenue Requirement Study. *See* PRS Documentation Tables 2.3.1.1–2.3.1.5. The disaggregated cost data are aggregated into BPA's ratemaking cost pools specified by section 7 of the Northwest Power Act. *See* Documentation Table 2.3.2. Sections 7(b) and 7(f) describe how costs associated with resource pools (FBS costs, exchange resource costs, and new resource costs) are to be allocated to load/rate pools. Section 7(g) describes how the costs associated with the other cost pools (conservation costs, BPA program costs, power-related transmission costs) are to be allocated to load/rate pools.

Functionalization of costs between the generation and transmission functions (BPA does not have a distribution function normal to most utilities) is performed in the Power Revenue Requirement Study and the Transmission Revenue Requirement Study. The costs functionalized to the generation function are included in the power revenue requirement found in the COSA modeling (one exception to this is exchange resource costs; *see* § 2.1.4.2). The exchange resource costs are calculated internal to the RAM2016. The exchange resource costs include transmission function costs. The exchange resource costs are functionalized in the COSA modeling so that only the generation portion of the exchange resource costs is subject to the power cost rate steps, and the transmission cost portion is then added back in after the Rate Directives Step is completed. *See* Documentation Table 2.3.4.2. In this way, the statutorily mandated power cost relationships between the various rate pools are maintained without being affected by the exchange transmission function costs.

The COSA modeling uses other costs that are internally generated by the RAM2016. These include exchange resource costs, some power purchase costs, revenue shortfall costs associated with some rate credits, and revenues from secondary power sales. These items are covered in greater detail below.

2.1.4.1 Revenue Requirement

The Power Revenue Requirement Study is based on power cost estimates for a two-year rate period, FY 2016–2017. A preliminary generation revenue requirement from the Power Revenue Requirement Study is supplemented in the COSA for costs that are determined in other steps of the ratemaking process: projected balancing purchase power costs; system augmentation costs; Planned Net Revenues for Risk (PNRR), if any; and the functionalized exchange resource costs. The annual revenue requirements used for rate calculations are shown in Documentation Table 2.3.2. Disaggregated costs are listed in a form consistent with the income statement from the Power Revenue Requirement Study and are shown in Documentation Table 2.3.1. RAM2016 uses key code mapping to allocate all costs to the COSA cost pools and the Tiered Rate Methodology (TRM) cost pools. Because of the different purposes of the COSA and the TRM, the COSA cost pools do not match the TRM cost pools; however, all costs appear in both sets of cost pools.

Three categories of purchased power are included in the COSA: (1) purchased power, (2) system augmentation, and (3) balancing power purchases.

Purchased Power. The purchased power subset of purchased power costs includes the costs of acquisition of power through renewable energy, wind, geothermal, and competitive acquisition programs. Costs of purchased power are included in the new resources pool.

System Augmentation. For ratesetting purposes, it is assumed that BPA acquires resources beyond the inventory represented by the system generating resources and balancing power purchases. These system augmentation acquisition amounts are determined in the Power Loads and Resources Study and are used to meet annual customer firm power loads in excess of annual firm system resources. The mean price from the Critical Water Run is used to value the cost of system augmentation. Power Risk and Market Price Study, BP-16-FS-BPA-04, § 2.6.2. System augmentation purchases are treated as FBS replacements and, as such, the costs are included in and allocated as FBS costs. *See* Documentation Tables 2.3.1 and 2.3.2.

Balancing Power Purchases. The costs of power purchases and storage required to meet firm deficits on a monthly/diurnal basis are included in the category of balancing power purchases. Projected balancing power purchases are generally needed to serve firm loads in months other than the spring fish migration period under some water conditions. Balancing purchase expenses are calculated for each monthly/diurnal period where BPA is deficit energy across all 3,200 iterations in the Revenue Simulation Model (RevSim). The median purchasing price and quantity associated with these purchases for each year of the rate period are passed to RAM2016 to compute balancing purchase costs. Power Risk and Market Price Study Documentation, BP-16-FS-BPA-04A, Tables 18 and 19. Balancing power purchases are treated as FBS replacements and, as such, the costs are included in and allocated as FBS costs. *See* PRS Documentation Tables 2.3.1 and 2.3.2.

2.1.4.2 Functionalization of Exchange Resource Costs

In the COSA, exchange resource costs are based on participating utilities' ASCs and their exchange power sales to BPA. Each utility's ASC includes the cost of power and transmission services associated with serving the utility's total retail load. By definition, exchange resource sales to BPA equal the exchange sales by BPA. The rate directive adjustments that occur subsequent to the COSA use the results of the COSA allocations of the generation revenue requirement. Therefore, because the exchange resource costs in the COSA include transmission costs, the PF Exchange rate includes a transmission cost adder, and the exchange resource costs are functionalized between power and transmission. The exchange resource costs functionalized to power continue through the ratemaking process. The exchange resource costs functionalized to transmission are removed from the generation revenue requirement for the Rate Directives Step and are added back to determine the PF Exchange rate after the Rate Directives Step is completed. In this way, the exchange resource costs functionalized to power are treated the same as other power function costs through the rate development process. The transmission function costs are collected directly from PFx loads through a transmission adder included in the PFx rate. Because the amount of exchange resource costs functionalized to transmission is equal to the increased revenue due to the PFx rate adder, there is no net cost of these transmission costs to other rates. The functionalization of exchange resource costs is shown in Documentation Table 2.3.4.2.

2.1.4.3 Low Density Discount

Section 7(d)(1) of the Northwest Power Act instructs BPA to apply a Low Density Discount (LDD) to mitigate the costs of customers with relatively fewer consumers spread over relatively larger geographic areas.

The cost of providing the discount is computed in RAM2016 using offset quantities and the internally computed TRM rates. Offset quantities are the sum of the applicable LDD percentages applied to the customer-specific billing determinants. *See* TRM, BP-12-A-03, § 10.2. These offsets are computed in the TRM Billing Determinants Model, which is a module of RAM2016.

The estimated cost of the LDD is shown in Documentation Table 2.3.3. The entire cost of the discount is allocated to the PF load pool prior to linking the IP rate to the PF rate.

2.1.4.4 Irrigation Rate Discount

A rate discount is available to qualifying irrigation loads pursuant to CHWM contracts and the TRM. The discount is a rate, expressed in mills per kilowatthour, that when applied to qualified irrigation load produces a dollar credit on eligible customers' power bills. The Irrigation Rate Discount (IRD) rate is calculated in RAM2016, as described in section 3.1.13.1 below. The cost of the discount is computed in RAM2016 using contract irrigation loads and the internally calculated rate. The entire cost of the IRD is allocated to the PF load pool prior to linking the IP rate to the PF rate.

2.1.4.5 Cost Pools

The COSA has six cost pools for the initial allocation of BPA's power costs: FBS resource costs, exchange resource costs, new resource costs, conservation costs, BPA program costs, and power transmission costs. These costs are allocated to the various customer load classes using direction from sections 7(b)(1), 7(f), and 7(g) of the Northwest Power Act.

2.1.4.5.1 Section 7(b)(1) costs

Section 7(b)(1) costs are associated with the resource cost pools necessary to serve PF load, including the PFp load and the PFx load. For the BP-16 rates, these resources include all of the FBS resources and a large portion of the exchange resources. Therefore, all FBS resource costs and most of the exchange resource costs are section 7(b)(1) costs allocated to serve section 7(b)(1) loads, that is, PF loads.

2.1.4.5.2 Section 7(f) Costs

Section 7(f) costs are associated with the resource cost pools necessary to serve non-PF load, including IP, NR, and FPS loads. For the BP-16 rates, these resources are a small portion of the exchange resources and all of the new resources. Therefore, a small portion of exchange resource costs and all new resource costs are section 7(f) costs allocated to serve all remaining loads, that is, IP, NR, and FPS loads.

2.1.4.5.3 Section 7(g) Costs

Conservation Costs. The Northwest Power Act requires BPA to treat cost-effective conservation savings as a resource in planning to meet the Administrator's obligations to serve loads. The "conservation" line item, as seen in Documentation Tables 2.3.1 and 2.3.2, includes (1) amortization of BPA's previous conservation resource acquisition activities; (2) BPA's continuing contributions to the region's market transformation efforts; (3) costs associated with BPA's energy efficiency business; and (4) a share of Net Revenues (Minimum Required Net Revenues (MRNR) plus PNRR, if any). *See* Documentation Table 2.3.7.4. Conservation costs are allocated to all rate pools using the Conservation EAFs. *See* Documentation Table 2.3.4.3.

BPA Program Costs. Some of BPA's program costs are not identified directly with any specific resource pool. An example is the cost of tracking and implementing national energy policies and initiatives. Development of these power program costs occurs in the Integrated

Program Review, as described in the Power Revenue Requirement Study § 2.1. The power portion appears in the COSA as BPA program costs. BPA program costs are allocated to all rate pools based on the Total Usage EAFs. *See* Documentation Table 2.3.4.3.

BPA Power Transmission Costs. Power transmission expenses include the costs of serving transfer service customers with Federal power wheeled under general transfer agreements (GTA) and other non-Federal transmission service agreements over a third-party transmission system. It also includes the costs Power Services incurs to procure transmission and ancillary services to transmit surplus Federal power to purchasers that do not hold transmission contracts, primarily outside the Pacific Northwest. Finally, it includes the costs of the FCRPS generation-integration segment, as determined in the Transmission Segmentation Study. Transmission costs are allocated to all rate pools based on the Total Usage EAFs. *See* Documentation Table 2.3.4.3.

2.1.4.6 Planned Net Revenues for Risk

PNRR is an amount of net revenues required to be recovered from power rates to ensure that cash flows from proposed rates meet BPA's probability standard for repaying Power Services' portion of Treasury payments on time and in full. PNRR may also include an amount of cash required to restore an accumulated negative balance of financial reserves attributed to Power Services. Under the ratemaking methodology, the amount of PNRR is the result of an iterative process among several models: RAM2016, RevSim, Non-Operating Risk Model (NORM), and ToolKit. *See* Power Risk and Market Price Study § 3.3. The iteration is initiated with a seed value for PNRR in Documentation Tables 2.3.1 and 2.3.2. The resultant rates are used in RevSim to produce net revenue probability distributions. These net revenue distributions are then used in the ToolKit to produce a new PNRR value. *See* Documentation Table 2.3.1. Because the PNRR is zero for the BP-16 rates, no iterative process is required to determine PNRR.

2.1.5 Revenue Credits

In addition to cost data, the COSA modeling incorporates allocation of various revenue credits as an offset to allocated costs to each pool. Allocation of revenue credits follows the same principles as the allocation of costs, based upon statutory guidance. Some of these revenue credits are associated with the operation of FBS resources and have the effect of reducing FBS resource costs to be recovered by PF rates, for example. There are also revenue credits that have the effect of reducing the new resource and conservation costs. Other revenue credits that are not associated with any particular cost pool are allocated to rate pools pro rata to load.

2.1.5.1 Downstream Benefits and Pumping Power Revenues

Downstream benefits and pumping power revenues are described in section 4.2. Downstream benefits and pumping power revenues are associated with FBS resources, and these credits are allocated to loads that have been allocated the costs of the FBS. *See* Documentation Table 2.3.6.

2.1.5.2 Section 4(h)(10)(C) Credits

Section 4(h)(10)(C) credits are described in section 4.4.1. The forecast credit is calculated as described in the Power Risk and Market Price Study, § 2.6.1, and supplied to RAM2016. Section 4(h)(10)(C) credits are associated with FBS resources, and these credits are allocated to loads that have been allocated the costs of the FBS. *See* Documentation Table 2.3.6.

2.1.5.3 FBS Contract Obligations Revenue

BPA has certain FBS system obligations that provide revenues. These include the pre-Subscription Hungry Horse reservation power sales contracts and some seasonal exchanges. These FBS system obligation revenues are associated with FBS resources and are allocated to loads that have been allocated the costs of the FBS. *See* Documentation Table 2.3.6.

2.1.5.4 Colville Credit

The Colville credit is described in section 4.4.2. The Colville credit is associated with FBS resources, and this credit is allocated to loads that have been allocated the costs of the FBS. Documentation Table 2.3.6.

2.1.5.5 Energy Efficiency Revenues

The Energy Efficiency revenue credit reflects revenues associated with the activities of BPA's Energy Efficiency program. These revenues are generally payments for reimbursable expenditures that are included in the generation revenue requirement. The Energy Efficiency revenue credit is allocated in the same way as BPA's conservation expenses and effectively reduces the amount of those expenses allocated to power rates. *See* Documentation Table 2.3.6.

2.1.5.6 Large Project Program (LPP) Revenues

This credit is associated with revenues collected under the Large Project Targeted Adjustment Charge (LPTAC). *See* GRSP II.A.2. These revenues recover from customers participating in the LPP the costs of acquiring conservation consistent with the Northwest Power Planning Council's applicable Power Plan for the upcoming rate period.

2.1.5.7 Miscellaneous Revenues

Miscellaneous revenues are described in section 4.2. These revenues are allocated to all firm load through the General Cost EAFs. *See* Documentation Table 2.3.6.

2.1.5.8 Renewable Energy Certificates

Revenues result from BPA's sales of Renewable Energy Certificates (RECs). The revenue is based on BPA's established price for RECs of $15.00 for FY 2016–2017 and renewable project output included in the FBS and new resource resource pools. The revenues from Klondike III

RECs are allocated to loads that have been allocated the costs of the FBS, and the revenues from new resources renewable resource RECs are allocated to loads that have been allocated the costs of the new resources. *See* Documentation Table 2.3.6.

2.1.5.9 General Revenue Credits

In the course of marketing power, Power Services generates transmission-related revenues and credits. The revenues and credits are predominantly revenues associated with providing reserves and energy for ancillary services, control area services, and other reliability needs. The source of these credits is the BP-16 Generation Inputs and Transmission Ancillary and Control Area Services Rates Partial Settlement Agreement. BP-16 Administrator's Record of Decision, BP-16-A-02, Appendix A. Revenues associated with Generation Inputs, Energy Shaping Service products for NLSL service, New Resource Flattening Service, and Resource Support Services for non-Federal resources are allocated to all loads through the General Cost EAFs. *See* Documentation Tables 2.3.7.5 and 2.3.7.6.

2.1.5.10 Secondary Revenue Credits

The Secondary Revenue Credit adjustment recognizes that BPA collects revenues from certain power sales to which costs are not allocated. BPA credits these revenues to classes of service served with firm Federal power.

The ratemaking process ensures that the forecast of firm resources available to serve load is equal to BPA's firm load obligations under critical water conditions. However, the ratesetting process also recognizes that better than critical water conditions will most likely occur. Generation from water in excess of critical water conditions is called secondary energy. The projected secondary energy revenue credits are included so that power rates are set at a level such that revenues from all sources do not recover more than the total Power Services revenue requirement.

The sales of energy in excess of firm obligations on a monthly/diurnal basis under 3,200 games of different risk conditions are calculated by RevSim. *See* Power Risk and Market Price Study § 2.2.3; *see also* Documentation Table 2.3.8. Median prices and quantities of these secondary sales, as well as mean market prices, are passed to RAM2016 for the purposes of the secondary revenue credit and the computation of the load shaping rates.

The secondary revenues projected in RevSim are for market sales expected to be made by BPA and do not include the portion of secondary energy that is expected to be sold to Slice customers. The ratemaking process does not consider product choice by preference customers until the Rate Design Step; therefore, the sales and revenue from RevSim are "grossed up" to reflect the market value for all secondary energy expected to be produced by Federal generation. *See* Documentation Table 2.3.8. Section 7(g) of the Northwest Power Act directs that all benefits from the sale of excess electric power not otherwise allocated under section 7 be equitably allocated to power rates in accordance with generally accepted ratemaking principles. Secondary energy revenues are allocated to rate pools based on the FBS and new resources energy allocation factors to credit the revenues against the costs of the resources producing the secondary energy. *See* Documentation Table 2.3.8.

2.1.6 Surplus Revenue Deficiency/Surplus Reallocation

BPA sells surplus firm power under the FPS rate schedule. The COSA includes these sales in the FPS rate pool and allocates costs to these sales. Sales of such firm power are not necessarily made at rates that recover the exact costs allocated in the COSA to these sales. Therefore, either a revenue surplus or a revenue deficiency will result when the costs allocated to the sales of this firm power are compared with the revenues received under the stipulated terms of the applicable contract. Revenue credits also include revenues from WNP-3 Settlement power sales to Avista and Puget Sound Energy and revenues collected in FY 2016 under the Slice Billing Adjustment for misallocations of costs associated with accrual revenues from the WNP-3 Settlement with Portland General Electric. The expected revenue forecast from the sale of firm power and settlements, the allocated costs, and the resulting revenue deficiency are shown in Documentation Table 2.3.9. This revenue deficiency is allocated to all other firm power (PF, IP, and NR) rates.

This is the final step of the COSA. At this point, all of BPA's costs have been allocated to the PF, IP, NR, and FPS rate pools, as have all revenues derived from sources other than the PF, IP, NR, and FPS rate pools. After completion of the COSA, certain statutory reallocations of these COSA-allocated costs are performed in the Rate Directives Step.

2.2 Rate Directives Step

2.2.1 Introduction

Northwest Power Act sections 7(c), 7(b)(2), and 7(b)(3) provide guidance for the Rate Directives Step. The Rate Directives Step reallocates costs among load pools to ensure that the relationships between the rates for the different classes of customers comport with the rate directives in the Northwest Power Act.

2.2.2 Rate Directives Step Modeling

The Rate Directives Step modeling takes as input the costs allocated to the four rate pools (PF, IP, NR, and FPS) from the COSA modeling. All costs and credits have been allocated to rate pools in the COSA. The Rate Directives Step adjusts the initial allocations among the PF, IP, and NR rate pools with reallocations of costs that conform with section 7 of the Northwest Power

Act. At this point in the modeling, the allocation of costs to the FPS rate pool is equal to the expected revenues from FPS sales and will not be altered throughout the remaining ratemaking steps.

2.2.2.1 First IP-PF Rate Link

The IP rate for sales of power to BPA's DSI customers is a formula rate tied to the unbifurcated PF rate (*i.e.*, the PF rate at this point in the modeling includes costs that will be allocated between the PFp rate and the PFx rate later in the process). Also at this point in the modeling, the costs allocated to the IP and NR rate pools are equal on a per-megawatthour basis. Therefore, an adjustment is needed to set the IP rate to its proper relationship with the PF rate. That adjustment, the IP-PF Link 7(c)(2) rate adjustment, will reduce the allocated costs to the IP rate pool and increase the costs allocated to the PF and NR rate pools.

The IP-PF Link adjustment sets the IP rate to be equal to the monthly/diurnal PFp energy rates applied to DSI billing determinants, plus the net industrial margin. The model first calculates the net industrial margin by subtracting the Value of Reserves provided by sales to the DSIs from the typical industrial margin calculated in the 7(c)(2) Margin Study, PRS Appendix A. *See* Documentation Table 2.4.1. Monthly and diurnally differentiated PF melded rates are calculated as described in section 3.1.14 below. *See* Documentation Tables 2.4.2 and 2.4.3. Because the IP-PF Link calculation maintains a set relationship between the levels of the IP and PF rates for each year and simultaneously allocates costs between the two rates, and to avoid multiple iterations, RAM2016 has an algebraic formula to approximate a solution and then uses an intrinsic Excel function, "Goal Seek," to converge to a solution for each year of the rate test period. *See* Documentation Table 2.4.4.

After the IP-PF Link reallocation, RAM2016 conducts an IP floor rate test to determine if the currently calculated IP rate is below the IP rate that was in effect for the contract year ending on June 30, 1985, as required by section 7(c)(2) of the Northwest Power Act. The currently modeled BP-16 IP rate at this point in the modeling is not below the IP floor rate, and no floor rate adjustment is needed.

2.2.2.2 Active Exchanging Utilities

With the proper relationship between the IP rate and the unbifurcated PF rate established, the Base PF Exchange rates for the IOUs and the COUs can be calculated. The Base PF Exchange rate for the IOUs is the average unbifurcated PF rate plus a transmission adder. The Base PF Exchange rate for the COUs begins with the IOU rate and removes Tier 2 costs and loads. A test is again conducted to determine if the ASCs of the potential IOU and COU exchanging utilities are greater than the IOU and COU Base PF Exchange rates. If a utility's ASC is greater than its Base PF Exchange rate, the utility becomes an active exchanging utility.

2.2.2.3 7(b)(2) Rate Protection and 7(b)(3) Reallocations

The next step is to calculate the level of rate protection due to preference customers pursuant to section 7(b)(2) of the Northwest Power Act. The BP-16 rates are calculated pursuant to a settlement of the outstanding litigation associated with the REP and the section 7(b)(2) rate test. 2012 Residential Exchange Program Settlement Agreement, Contract No. 11PB-12322 (2012 REP Settlement), REP-12-A-02A, at 1. The 2012 REP Settlement was previously evaluated for compliance with, among other statutory provisions, sections 7(b)(2) and 7(b)(3).

Rate modeling for the REP under the 2012 REP Settlement begins with total IOU REP benefits, as specified in the 2012 REP Settlement and known as Scheduled Amounts. Added to this total IOU REP benefit amount are the Refund Amounts, also specified in the 2012 REP Settlement.

The Refund Amounts are credited back to preference customers in the form of a credit on their power bills. Together these amounts are referred to as REP Recovery Amounts. *See* Documentation Table 2.4.9.

The REP Settlement rate modeling first calculates the Unconstrained Benefits, which are the REP benefits that would be in place if there was no PFp rate protection. In such circumstance, the REP benefits for each exchanging utility would be its ASC minus its appropriate Base PFx rate multiplied by its qualified exchange load. The Unconstrained Benefits are shown in Documentation Table 2.4.10. These Unconstrained Benefits are then used to calculate COU REP benefits, as specified in individual settlements with each eligible COU. COU REP benefits are calculated using a ratio of (i) the IOU Scheduled Amounts plus COU Refund Amount to (ii) the total IOU Unconstrained Benefits for IOUs. This ratio is then multiplied by COU Unconstrained Benefits to derive COU REP benefits.

The total rate protection provided to preference customers is composed of two parts. With the Unconstrained Benefits and the total IOU and COU REP benefits determined, the first part of rate protection due to preference customers is calculated as the Unconstrained Benefits minus the sum of REP benefits. The REP Settlement modeling then allocates this amount to individual REP participants. Next, the cost of providing Refund Amounts is allocated to the IOU REP participants. The sum of these two specific allocations to each REP participant is divided by the exchange load for each participant, calculating a utility-specific 7(b)(3) Surcharge that is added to the appropriate Base PFx rates to produce a utility-specific PFx rate. *See* Documentation Table 2.4.11. After the utility-specific PFx rates are calculated, the utility-specific REP benefits are calculated and summed. *See* Documentation Table 2.4.11 and Table 2.4.12, which describes reallocations between participating IOUs pursuant to section 6.2 of the 2012 REP Settlement Agreement.

A second part of rate protection, the REP Surcharge, is calculated and allocated to the IP and NR rate pools. The REP Surcharge is determined by multiplying the REP benefit costs determined above (REP Recovery Amounts plus COU REP benefits) by a scalar specified in the 2012 REP Settlement. The scalar is based on the WP-10 7(b)(3) rate surcharge to the IP and NR rates and changes this historical 7(b)(3) rate surcharge as REP Recovery Amounts change. The REP Surcharge, when multiplied by the forecast sales under the IP and NR rate schedules, produces an amount of rate protection dollars. *See* Documentation Table 2.4.13. This amount is allocated to the IP and NR rate pools.

The RAM2016 REP Settlement modeling explicitly adjusts dollars among the PFp, PFx, IP, and NR rate pools. The REP Settlement rate protection allocations increase the IP, NR, and PFx rates while decreasing the PFp rate. *See* Documentation Table 2.4.14.

2.2.2.4 Second IP-PF Rate Link

After the IP and NR adjustment, the now-lower PFp rate and the now-higher IP rate must be adjusted to maintain the proper 7(c)(2) rate directive cost relationship. For this second IP-PF Link calculation, monthly/diurnal PFp energy rates are determined, and the IP rate is set equal to the flat PFp rate plus the net Industrial Margin plus the REP Surcharge. *See* Documentation Tables 2.4.16, 2.4.17, and 2.4.18.

2.2.3 IP Rate

The IP rate is calculated using directives in sections 7(c)(1), 7(c)(2), and 7(c)(3) of the Northwest Power Act. Section 7(c)(1)(B) provides that, after July 1, 1985, the rates to DSI customers will be set “at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region.” “Equitable in relation” pursuant to section 7(c)(2) is defined as basing the DSI rate on

BPA's "applicable wholesale rates" to its COU customers plus the "typical margins" included by those customers in their retail industrial rates. Section 7(c)(3) provides that the DSI rate is to be adjusted to account for the value of power system reserves provided through contractual rights that allow BPA to restrict portions of the DSI load. This adjustment is made through a Value of Reserves credit. Thus, the rate for the DSIs, the IP rate, is set equal to the applicable wholesale rate, plus the typical margin, plus the VOR credit, subject to the DSI floor rate test and the outcome of the determination of PFp rate protection.

2.2.3.1 Applicable Wholesale Rate

The applicable wholesale rate is calculated as the rate(s) at which BPA is selling power to COUs, that is, the PFp rate (for general requirements, as defined in section 7(b)(4) of the Northwest Power Act) and the NR rate (for New Large Single Loads). The IP rate begins by being set to the average of the PF and NR rates, weighted by sales to COUs at each rate and reflecting the DSI class load factor. No sales to COUs at the NR rate are projected for this rate period.

2.2.3.2 Typical Margin, Value of Reserves, and Net Industrial Margin

As noted above, the DSI rate is set by adding the typical margin and VOR credit to the applicable wholesale rate. The typical margin is calculated as described in section 3.3.1.2 and Appendix A. The VOR credit is calculated as described in section 3.3.1.1. The typical margin plus the VOR credit yields the net industrial margin. The net industrial margin is added to the applicable wholesale rate, and the result is multiplied by the forecast DSI load to determine the allocated costs for the IP rate pool. *See* Documentation Table 2.4.1.

2.2.3.3 IP-PF Link 7(c)(2) Adjustment

The IP-PF Link 7(c)(2) adjustment accounts for the difference between the revenues expected to be recovered from the DSIs at the final IP rate and the costs allocated to the rate. This difference, known as the 7(c)(2) Delta, is allocated to non-DSI rates, primarily the PF rate. Because the allocation of the 7(c)(2) Delta changes the PF and the NR rates, together forming the applicable wholesale rate upon which the IP rate is based, the 7(c)(2) Delta must be recalculated. The interaction between the applicable wholesale rate and the IP rate has been reduced to an algebraic formula to approximate a solution, and then the RAM uses an intrinsic Excel function, "Goal Seek," to converge to a solution for each year of the rate test period. *See* Documentation Table 2.4.4.

2.2.3.4 IP Floor Rate Verification

Section 7(c)(2) of the Northwest Power Act requires that the rates to DSI customers shall not be less than the rates in effect for the contract year ending June 30, 1985 (the floor rate). Accordingly, a test is performed to determine if the IP rate is at a level below the 1985 IP rate. If so, an adjustment is made that raises the IP rate to the floor rate and credits other customers with the increased revenue from the DSIs. If the IP rate is set at a level above the floor rate, no floor rate adjustment is necessary.

The first step in calculating the floor rate is to apply the IP-83 Standard rate components to rate period (FY 2016–2017) DSI billing determinants. The resulting revenue figure is divided by total IP rate period energy loads to arrive at an average rate in mills per kilowatthour. This rate is reduced by an Exchange Cost Adjustment and a Deferral Adjustment that were included in the IP-83 rate but are no longer applicable. Both adjustments are made on a mills per kilowatthour basis.

In addition, the transmission component of the IP-83 rate is removed to allow a power-only floor rate comparison. The floor rate is adjusted for transmission costs by subtracting total transmission costs in mills per kilowatthour from the IP-83 rate in the same manner that the

Exchange Cost Adjustment and Deferral Adjustment are removed. The mills per kilowatthour component is determined by dividing total transmission costs in the IP-83 rate by the total energy billing determinants for that rate period. *See* Documentation Table 2.4.6.

These calculations result in an undelivered IP floor rate. The floor rate is applied to the current rate period DSI billing determinants to determine floor rate revenue. Revenue at the proposed IP rates is compared to the revenue at the floor rate. Because revenue from the proposed IP rate is greater than the floor rate revenue, no floor rate adjustment is necessary. *See* Documentation Tables 2.4.6 and 2.4.7.

2.2.4 Section 7(b)(2) Rate Protection

The rate test specified in section 7(b)(2) of the Northwest Power Act ensures that BPA's rates for public body, cooperative, and Federal agency customers (collectively referred to as preference customers or 7(b)(2) customers) are no higher than rates calculated using specific assumptions that remove certain effects of the Northwest Power Act. For BP-16 rates, the rate test was performed in the assessment of the 2012 REP Settlement. The 2012 REP Settlement was found to be in compliance with the rate test, and rates are established pursuant to the 2012 REP Settlement.

2.3 Rate Design Step

2.3.1 Statutory Background

BPA's rates must follow the ratesetting directives of section 7, but, as noted in the legislative history of the Northwest Power Act, the rate directives govern the amount of revenue the Administrator collects from each class of customers, not the rate form. *See, e.g.*, H.R. Rep. No. 96-976, pt. 1, at 69 (2d Sess.1980). Section 7(e) reserves rate design (how the revenue is collected) to the Administrator.

The Rate Design Step uses the results of the cost and credit allocations of the COSA Step, as modified by the Rate Directives Step, to develop the rate components that will recover the costs allocated to each rate pool. Three distinct rate designs are developed: (1) a tiered rate design for the PFp rate, in which the Tier 1 rates are designed using customer charges and demand and energy rates; (2) a traditional demand and energy design for the PFp Melded rate, the IP rate, and the NR rate; and (3) a fixed annual energy rate for each PFp Tier 2 rate and the PFx rates.

2.3.2 Rate Design Step Modeling

Based on the results of the Rate Directives Step, RAM2016 designs rates for each rate pool. For the PFp Melded rate, the PFx rate, the IP rate, and the NR rate, the rate design can be applied without further processing. The design of the PFp Melded rate is described in section 3.1.14. The design of the PFx rate is described in section 3.2. The design of the IP rate is described in section 3.3. The design of the NR rate is described in section 3.4.

2.3.2.1 TRM Rate Modeling

Additional processing is required before the PFp rate design can be calculated. The allocations of costs and credits performed in the COSA Step and Rate Directives Step are insufficient to inform the rate design of the PFp rate. The TRM specifies a cost allocation methodology to separate costs into the various TRM cost pools in a manner different from the COSA's cost allocation. RAM2016 accomplishes the TRM cost allocation through a process of mapping disaggregated costs and credits to the TRM cost pools. To provide a crosswalk between the differences between COSA allocations and TRM allocations, the mapping for each is shown within RAM2016, as described below.

The mapping of costs to the TRM cost pools includes costs passed from the Power Revenue Requirement Study, credits passed from the revenue forecast, and cost and credit line items internally computed in RAM2016. Internally computed line items include:

- Costs of IRD and LDD programs.
- Revenues associated with power sales to DSI customers at the IP rate.
- Revenues and costs associated with the Residential Exchange Program:
    - Revenues are calculated at the PFx Rates, incorporating REP surcharges. Loads are included only for customers qualifying for exchange benefits.
    - Costs are calculated using the ASC and exchange load for each qualifying REP participant.
- Revenues associated with power sales at the NR rate.
- System augmentation costs required to achieve annual load-resource balance.
- Balancing power purchase costs required to serve the monthly/diurnal loads of Load Following customers.
- "Balancing" augmentation power purchases associated solely with provision of power at the Load Shaping rate on a net annual basis. (Load Shaping rate loads would equal zero on a net annual basis except that Above-RHWM loads less than one average megawatt are allowed to forgo purchasing at Tier 2 rates and be served at the Load Shaping rate.)
- Secondary energy revenue credit.
- Revenues allocated for Unused RHWMs. *See* § 3.1.3.2.
- Demand and Load Shaping revenues. *See* §§ 3.1.2.4 and 3.1.2.3.
- Costs of network real power losses on sales to non-Slice preference customers. *See* § 3.1.3.1.
- Costs and credits for conservation acquisitions in the Large Project Program. *See* § 3.1.6.6.

- Credits from the Slice Billing Adjustment associated with recouping misallocation of PGE WNP#3 settlement non-cash revenues. *See* § 3.1.6.5.
- Costs associated with NR shaping and capacity services allocated to the Non-Slice Customer Charge. *See* § 3.4.3.
- Tier 2 overhead costs and other cost assignments. *See* § 3.1.4.

Once all costs have been mapped into TRM cost pools, the rate design for the PF Public rate can be applied.

2.3.3 PF Public Rate Design Step for Tiered Rates

The rate design for the PFp rate is established in the TRM. The TRM specifies that all costs and credits comprising BPA's total power revenue requirement be allocated to one of four customer charge cost pools: Composite, Non-Slice, Slice, or Tier 2. The Tier 2 cost pool is further divided into Short-Term, Load Growth, VR-1-2014, and VR-1-2016 vintage cost pools. After reflecting the cost allocations to other rate pools, the end result of the TRM cost allocations is that the total costs allocated to the four customer charge cost pools will equal the total costs allocated to the PFp rate pool in the COSA Step and the Rate Directives Step. Thus, the TRM cost allocations neither increase nor decrease the cost allocations to the PFp rate pool after the Rate Directives Step. A demonstration of this equivalence is shown in Documentation Table 2.5.8.2.

While the TRM cost allocations do not change the costs allocated to the PFp rate pool, they do assign cost responsibility to the rates paid by customers purchasing the three primary products offered in the CHWM contracts: Slice/Block, Load Following, and Block. In addition, the TRM cost allocations recognize that, even though the ratesetting methodology described in this section is performed as if the REP is an actual purchase and sale of power, at this point in the ratesetting process the PFp rate can be determined based on its allocated share of the total REP benefit costs, rather than exchange resource costs and PFx revenues.

2.3.3.1 Composite Cost Pool

Except for costs and credits distinctly associated with a particular primary product, all Tier 1 costs and credits are allocated to the Composite cost pool. The Composite cost pool forms the cost basis for the Composite customer rate, which is paid by all preference customers with a CHWM contract.

2.3.3.2 Non-Slice Cost Pool

Tier 1 costs and credits, primarily secondary revenues, that are not associated with the Slice product are allocated to the Non-Slice cost pool. The Non-Slice cost pool forms the cost basis for the Non-Slice customer rate, which is paid by preference customers that have selected the Load Following product or the Block product; it is also paid by customers selecting the Slice/Block product for their Block purchases.

2.3.3.3 Slice Cost Pool

Tier 1 costs and credits that are associated with the Slice product are allocated to the Slice cost pool. The Slice cost pool forms the cost basis for the Slice customer rate, which is paid by preference customers that have selected the Slice/Block product for their Slice purchases. In the BP-16 rates there are no costs allocated to this cost pool.

2.3.3.4 Tier 2 Cost Pools

Costs and credits that are associated with the sale of power to serve a customer’s Above-RHWM load are allocated to Tier 2 cost pools. Generally, the costs allocated to a Tier 2 cost pool are purchase power costs designated by BPA as being for this purpose. In addition to purchase power costs, Tier 2 rates are established to recover Resource Support Services, overhead, and other BPA costs that are not necessarily incurred solely for the purpose of serving Above-RHWM load but support making such sales. The initial allocation of these other costs is to either the Composite cost pool or the Non-Slice cost pool. Therefore, the portion of the revenues expected to be received from sales at a Tier 2 rate is reassigned to the cost pool where the initial allocation is made. *See* Documentation Table 2.5.7.2.

2.4 Rate Modeling Iterations

Several iterations—both internally within RAM2016 and externally between other models and RAM2016—are required before the ratesetting process is complete. These iterations ensure that the appropriate costs are computed and allocated consistent with the principles of the Northwest Power Act and TRM rate design.

2.4.1 Iterations Internal to the Model

2.4.1.1 Participation in the Residential Exchange Program

Participation in the REP requires that the applicable Base PFx rate is less than a participant's ASC. The applicable Base PFx rate is either the Base Tier 1 PFx rate for COUs or the untiered Base PFx rate for IOUs. If a utility has an ASC less than its applicable Base PFx rate, that utility is ineligible to participate in the REP. RAM2016 uses a macro loop feature to test whether, for each year of the exchange period, each utility with an ASC qualifies for the REP. If a utility does not qualify, a binary index is used to exclude it, and if it does qualify, the index is set to include it. This test is done such that the exchange resource costs are calculated including the resources purchased from only REP participants, and before the Rate Directives Step of the 7(c)(2) linking of the IP and PF rates, the determination of rate protection, and subsequent reallocation of rate protection.

2.4.1.2 Costs of Rate Discounts

The costs of the LDD and IRD (*see* §§ 2.1.3.3 and 2.1.3.4 above) are mathematically related to Composite, Non-Slice, and Slice customer charges, and these charges are dependent on REP benefits and IP and NR revenues. LDD and IRD costs are indeterminate until final charges are set; however, because final charges depend in part upon the costs associated with these other factors, iteration in the model is necessary. As explained in sections 2.1.3.3 and 2.1.3.4, RAM2016 computes the cost of the LDD based on offset quantities and the IRD rate based on a historical percentage, which are applied to internally computed customer charges. For each iteration of the model, the appropriate charges are applied and new discount costs are computed. These new discount costs are allocated in the COSA Step, and the Rate Directives Step and TRM Step are performed again. New charges and rates are computed, which are again applied to the discount calculations. The iterative process continues until convergence.

2.4.1.3 Contract Formula Rates

If a power sales contract rate was computed based on the results of rate modeling, an iterative approach might be required to solve for the amount of revenue to be credited in the COSA Step. No internal iterations are currently required to model contracts at formula rates.

2.4.2 Iterations External to the Model

Some aspects of the ratesetting process are dependent upon the rates computed in RAM2016. Many of these dependencies have been integrated within RAM2016, as described above. Other dependencies are simply too large to incorporate into one model. Thus, external iterations must be performed before rates can be finalized.

2.4.2.1 Consumer-Owned Utility Average System Costs

The ASCs of COUs participating in the REP are based in part on the cost of power purchased from BPA at rates determined in RAM2016. The amount of Refund Amount that the COU will receive is also dependent upon the COU's Tier 1 Cost Allocator (TOCA). These two factors require a recomputation of ASCs for COUs based on the PFp rate level and the Refund Amount. This iteration is manually performed between RAM2016 and the ASC forecast model. Revised ASCs are included in RAM2016 and rate levels are recomputed until the results converge.

2.4.2.2 Risk Analysis and Mitigation: PNRR

The amount of PNRR is the result of an iterative process among four models: RAM2016, RevSim, NORM, and ToolKit. *See* Power Risk and Market Price Study, § 3.3. The iterative process is initiated with a seed value for PNRR in the revenue requirement used in RAM2016. The resultant rates are used in RevSim and NORM to produce distributions of net revenues. These distributions are then used in the ToolKit to produce a new PNRR value for the RAM2016 revenue requirement. Because PNRR for the BP-16 rates is determined to be zero, no iterative process is required to determine rate levels for the BP-16 rates.

2.4.2.3 Revised Revenue Test

The revenue forecast quantifies the expected level of sales and revenue from power rates and other sources for the rate period, FY 2016–2017. Two revenue forecasts are prepared, one with current rates and the other with proposed rates. These forecasts are used to test whether current rates will recover the generation revenue requirement and, if not, whether proposed rates are sufficient to recover the generation revenue requirement. The revised revenue test is described in section 4 below and in the Power Revenue Requirement Study, BP-16-FS-BPA-02, § 3.3. The power rates placed in effect October 1, 2013, are used in the calculation of revenue at current rates for FY 2016–2017, using the load forecast from the Power Loads and Resources Study.

The rates as computed in RAM2016 are applied to the same loads to create a revenue forecast at proposed rates for FY 2016–2017. The revenue from this forecast is shown in Documentation Table 4.2. These revenues are incorporated into the revenue test in the Power Revenue Requirement Study to determine if the proposed rates are sufficient to recover the revenue requirement. If the rates are not sufficient, an adjustment to the rates is required to increase the rates to a level sufficient to recover the revenue requirement.

The revised revenue test demonstrates that the BP-16 rates are sufficient to recover the revenue requirement, and no further rate adjustment is needed. *See* Power Revenue Requirement Study, BP-16-FS-BPA-02, § 3.3.

3. RATE DESIGN

As described in section 2.3 above, the Administrator retains a considerable amount of discretion in designing rates, as long as the rates meet the requirements of section 7 of the Northwest Power Act.

Rate design is applied after BPA has allocated its total power revenue requirement to five rate pools: Priority Firm Public Power, Priority Firm Exchange Power, Industrial Firm Power, New Resources Firm Power, and Firm Power and Surplus Products and Services. Rate design does not change the amount of the revenue requirement allocated to each of the five rate pools. Rather, rate design determines how the revenue requirement is collected through rates for each of the five rate pools. Rate design resolves the revenue collection within a particular rate pool and distinguishes between different types of service and power consumption of individual wholesale power customers. Rate design is also used to convey price signals to customers to encourage more efficient power usage and differentiates between the relative market values of the products and services BPA offers to its customers.

3.1 Priority Firm Public Rate Design

PFp rate design applies to purchases by public bodies, cooperatives, and Federal agencies pursuant to CHWM contracts. PFp rate design conforms to the criteria set forth in the Tiered Rate Methodology, BP-12-A-03.

As described in the TRM, the PFp rate design includes two tiers. The costs and credits functionalized to power are allocated to the Tier 1 and Tier 2 cost pools based upon the principle of cost causation. As specified in the TRM, the forecast costs and credits allocated to Tier 1 cost pools are kept separate and distinct from those allocated to the Tier 2 cost pools.

Aside from Tier 1 and Tier 2 rates, two other rates are calculated based on the TRM "component" rates. First is the PFp Tier 1 Equivalent Rate, for use in contracts that have rates tied to a traditional PF HLH/LLH rate design. Second, a PFp Melded rate schedule is included to serve loads of preference customers without CHWM contracts.

3.1.1 PFp Customer Cost Pools

Under the TRM, there are three Tier 1 cost pools (Composite, Non-Slice, and Slice) and the possibility of multiple Tier 2 cost pools. For the FY 2016–2017 rate period there are four Tier 2 cost pools: Short-Term, Load Growth, VR1-2014, and VR1-2016. The method by which costs and credits are allocated among the seven PFp cost pools is prescribed by the TRM. Costs and credits are allocated among the cost pools based on the association of the cost or credit with a product (Load Following, Block, or Slice/Block) and a tier (Tier 1 or Tier 2). The Composite cost pool includes all Tier 1 costs and credits that are not otherwise allocated to the Slice and Non-Slice cost pools. The Slice cost pool includes only those costs and credits that are specifically and uniquely attributed to the Slice product. Likewise, the Non-Slice cost pool includes only those costs and credits that are specifically and uniquely attributed to the Load Following and Block products (including the Block portion of the Slice/Block product). The Tier 2 Short-Term, Load Growth, VR1-2014, and VR1-2016 cost pools include all costs and credits that are attributable to the resources and services necessary for load served at a Tier 2 rate (except for Above-RHWM load served at Load Shaping rates).

To calculate the Tier 1 and Tier 2 rates, all costs recovered through power rates are allocated to one of the seven PFp cost pools. As described in section 2.1, these same costs and credits are first allocated to the PF, IP, NR, and FPS rate pools to establish the revenue requirement for each rate pool. Then, to avoid double-counting and over-collection of the costs and credits allocated to rate pools other than PFp, the revenues recoverable from those other rate pools reduce the

costs allocated to the seven PFp cost pools. A mathematical proof is included in RAM2016 which shows that the revenue requirement allocated to the PFp rate pools in the COSA equals the revenue collected from the seven cost pools under the PFp tiered rate design.
See Documentation Tables 2.5.7.1 and 2.5.7.2.

Once costs and rate design revenue credits have been balanced with the revenue requirement, additional adjustments to the PFp cost pools are made to the extent necessary to avoid cost shifts among products (Load Following, Block, and Slice/Block) and tiers (Tier 1 and Tier 2). These rate design adjustments move dollars from one cost pool to another through equal credits and debits and do not change the total revenue requirement for PFp. These rate design adjustments include three adjustments made within Tier 1 (section 3.1.3) and one adjustment made between Tier 1 and Tier 2 (section 3.1.4). The three adjustments made within Tier 1 are the Transmission Loss Adjustment, the Firm Surplus and Secondary Adjustment from Unused RHWM, and the Balancing Augmentation Adjustment. The one adjustment made between Tier 1 and Tier 2 is the Tier 2 Overhead Adjustment. The complete allocation of costs with all revenue credits and adjustments for the seven cost pools is shown in Documentation Table 2.3.5, and the TRM allocation of cost pool adjustments is shown in Documentation Tables 2.5.6.1 – 2.5.6.3.

3.1.2 Rate Design Revenue Credits

The Composite and Non-Slice cost pools contain credits for revenues collected from other components of the PFp rates. The Composite cost pool includes a credit for forecast revenue from the capacity components of Resource Support Services. The Non-Slice cost pool includes a credit for forecast revenue from the Load Shaping charge, the Demand charge (under both the Priority Firm and New Resource rate schedules), the energy components of Resource Support Services, the NR Resource Flattening Service charge, and the Resource Shaping charges. All of these rate design credits are necessary to ensure that the PFp rates do not over-collect the allocated revenue requirement and that the costs and credits have been allocated as specified in the TRM.

3.1.2.1 Resource Support Services (RSS) Revenue Credit

BPA provides RSS and RSS-related service options, which generate revenue from preference customers. Revenues received from the capacity components of RSS are credited to the Composite cost pool. For transparency purposes, BPA committed in the TRM to apply the applicable RSS to resources serving system augmentation needs (currently Klondike III) and to resources supporting the Tier 2 rates, if appropriate. In these situations, the source of the RSS revenue credit to the Composite cost pool is provided through either an RSS adder to the system augmentation cost or an RSS cost within a Tier 2 cost pool. Revenues provided by the energy components of RSS are credited to the Non-Slice cost pool. Unlike the capacity used to provide RSS, which operationally impacts Slice/Block, Block, and Load Following products, the provision of RSS energy impacts operationally the Non-Slice products only (including the Block portion of the Slice/Block).

The total annual RSS revenue credit for FY 2016–2017 is shown in Documentation Table 3.1.

3.1.2.2 Resource Shaping Charge (RSC) Revenue Credit

All balancing purchase costs, either resource or load, are allocated to the Non-Slice cost pool. The RSC collects additional revenues for balancing purchase costs associated with balancing resources against a flat annual block. To pair cost allocation with revenue collection of balancing purchase costs, the forecast RSC revenue credit is applied to the Non-Slice cost pool.

BPA committed in the TRM to apply the RSS and the RSC to resources serving system augmentation needs (Klondike III) and to resources supporting the Tier 2 rates in order to make these acquisitions financially equivalent to a flat block. *See* TRM, BP-12-A-03, § 8. In these situations, the source of the RSC revenue credit is provided through either an RSC adder to the system augmentation cost or an RSC adder within a Tier 2 cost pool. The forecast annual RSC revenue credit for FY 2016–2017 is shown in Documentation Table 3.1.

3.1.2.3 Load Shaping Revenue Credit

The Load Shaping charge is designed to recover costs associated with shaping the firm output of the Tier 1 System Resources to the monthly/diurnal shape of a customer's Tier 1 load. The Load Shaping charge applies to Non-Slice products, Block (including the Block portion of the Slice/Block) and Load Following, but not the Slice portion of the Slice/Block product. As stated in the TRM, BP-12-A-03, section 5.2, forecast revenue from the Load Shaping charge is credited to the Non-Slice cost pool by means of the Load Shaping Revenue Credit.

3.1.2.4 Demand Revenue Credit

The Priority Firm Demand charge is designed to send a price signal to a limited portion of a customer's overall demand on BPA and applies to customers purchasing Load Following and Block with Shaping Capacity products. Forecast revenue from the Demand charge is credited to the Non-Slice cost pool by means of the Demand Revenue Credit.

3.1.2.5 NR Revenue Credit

The New Resources rate schedule includes a Resource Flattening Service (NRFS), which is available to Load Following customers applying the actual generation output of a Specified Resource to a New Large Single Load (NLSL). The New Resource rate schedule also includes the Energy Shaping Service (ESS), which includes a capacity (demand) component. Forecast revenue from the NRFS and the capacity component of the ESS is credited to the Non-Slice cost pool by means of the NR Revenue Credit.

3.1.3 Rate Design Adjustments Made Between Tier 1 Cost Pools

3.1.3.1 Transmission Loss Adjustments

The Transmission Loss Adjustments provide a credit to the Composite cost pool and an equal debit to the Non-Slice cost pool based on Non-Slice transmission losses. The Transmission Loss Adjustments address the different accounting of transmission losses for the Slice/Block and Non-Slice products. The Non-Slice products and the Block portion of the Slice/Block products are delivered to the purchaser's load service area, while the Slice product is delivered to the purchaser at BPA's generation bus bar. The cost of generating the real power losses for the transmission of Non-Slice sales is included in BPA's revenue requirement. Conversely, the cost of generating the real power losses for the transmission of Slice sales is borne by the purchaser. The Transmission Loss Adjustments transfer the cost of generating the real power losses for the transmission of Non-Slice PF sales from the Composite cost pool to the Non-Slice cost pool. The Transmission Loss Adjustments are calculated by multiplying the network losses associated with the Non-Slice PF products, including the Block portion of the Slice/Block product, by the Average Slice and Non-Slice Tier 1 rate. *See* Documentation Table 2.5.6. The calculation and result of the Transmission Loss Adjustments are shown in Documentation Table 2.5.3.

3.1.3.2 Firm Surplus and Secondary Adjustments from Unused RHWM

Unused RHWM occurs when a customer's Forecast Net Requirement is less than its RHWM. The Firm Surplus and Secondary Adjustments from Unused RHWM reallocate costs between the Composite cost pool and the Non-Slice cost pool.

Unused RHWM reduces the need for system augmentation and/or increases firm power available for sale in the market. The reduced augmentation expenses and/or increased firm power market revenues are reflected in three lines on the TRM cost table: (1) Augmentation Power Purchases; (2) Secondary Revenue; and (3) Balancing Purchases. *See* Documentation Table 2.5.1. The

Augmentation Power Purchases line is part of the Composite cost pool, and the Secondary Revenue and Balancing Purchases are part of the Non-Slice cost pool. To share the entire benefit of Unused RHWM with all customers, the Composite and Non-Slice cost pools contain a Firm Surplus and Secondary Adjustment (from Unused RHWM), with one reflecting a credit and the other an equal debit.

The Firm Surplus and Secondary Adjustments have two purposes. The first is to reflect the difference between the value of a flat annual block of system augmentation and the value of the Unused RHWM when the Unused RHWM displaces augmentation. The difference between a flat annual block of system augmentation and the shape of the Unused RHWM is reflected in changes in the assumed balancing purchases and associated costs. These changes in balancing purchase costs are captured in the Non-Slice cost pool. A Firm Surplus and Secondary Adjustment reallocates the change in balancing purchase costs associated with the difference in value from the Non-Slice cost pool to the Composite cost pool.

The second purpose of the Firm Surplus and Secondary Adjustments is to reflect the full value of the Unused RHWM when the Unused RHWM creates firm surplus power. The revenue associated with this change in firm surplus power related to the Unused RHWM is reflected in the secondary revenue credit in the Non-Slice cost pool. A Firm Surplus and Secondary Adjustment reallocates this change in secondary revenues associated with the Unused RHWM from the Non-Slice cost pool to the Composite cost pool.

The value of Unused RHWM consists of portions of RHWM Augmentation, Tier 1 System Firm Critical Output, and an associated portion of secondary energy. Each of these three components is valued at its respective price: the Augmentation price for the RHWM Augmentation component, the market price (as expressed by the Load Shaping rates) for the Tier 1 System

Firm Critical Output component, and the market price (as expressed by the average price received for secondary sales) for the secondary component. The value of Unused RHWM (expressed in dollars per megawatthour) also will be calculated for use in the Slice True-Up of the Firm Surplus and Secondary Adjustment line item in the Composite cost pool. *See* Documentation Table 2.5.2 for results and calculation of the Firm Surplus and Secondary Adjustments from Unused RHWM and the dollar per megawatthour Slice True-Up value of Unused RHWM.

3.1.3.3 Balancing Augmentation Load Adjustments

As explained further in the subsections below, balancing augmentation load is (1) Above-RHWM load that is forecast to be served at Load Shaping rates; (2) load that is forecast to be served at Tier 2 rates or with a non-Federal resource, rather than at the appropriate Tier 1 rates (net negative Load Shaping billing determinants); or (3) changes to the Tier 1 System during the applicable 7(i) ratesetting process from that used to establish each customer's allocation of the Tier 1 System during the applicable RHWM Process.

The sum total of these conditions is either a charge or credit to the Composite cost pool and an offsetting credit or charge, respectively, to the Non-Slice cost pool. *See* Documentation Tables 2.5.6.1 and 2.5.6.2.

3.1.3.3.1 Above-RHWM Load that is Forecast to be Served at Load Shaping Rates

This first condition occurs when Above-RHWM load is forecast to be served at Load Shaping rates either (a) when a Load Following customer's annual Above-RHWM load is less than 8,760 MWh and the Load Following customer made no alternative election to serve its Above-RHWM load or (b) when Above-RHWM load is determined in the RHWM Process and the load forecast is updated during the rate proceeding to reflect the forecast of a larger load.

When either (a) or (b) is true and the amount of system augmentation purchases is equal to or greater than the amount of balancing augmentation load, the acquisition costs attributable to supplying balancing augmentation load are included as a system augmentation expense in the Composite cost pool. The revenue from supplying balancing augmentation load is credited to the Non-Slice cost pool through the Load Shaping charge revenue credit. Without a Balancing Augmentation Load Adjustment, only Non-Slice customers would receive a credit through an increased Load Shaping Charge revenue credit, but both Slice and Non-Slice customers would bear the cost of an increased system augmentation expense. The Balancing Augmentation Load Adjustment corrects this inequity with a credit to the Composite cost pool and an equal debit to the Non-Slice cost pool.

This condition causes the sum of Load Shaping billing determinants to be positive. The Balancing Augmentation Load Adjustments to the Composite and Non-Slice cost pools are calculated as the lesser of the sum of the Load Shaping billing determinants for each fiscal year or the augmentation amount for each fiscal year. The result is multiplied by the augmentation price for the respective fiscal year.

3.1.3.3.2 Load that is Forecast to be Served at Tier 2 Rates or with a Non-Federal Resource

This second condition occurs when load that would otherwise be served at Tier 1 rates is served at Tier 2 rates or with a non-Federal resource when Above-RHWM load is determined and the load forecast is updated during the rate proceeding to reflect the forecast of a smaller load. When this condition occurs, there is a reduction in system augmentation expenses from what would have otherwise occurred. The Composite cost pool would have received an implicit reduction in costs due solely to load variation attributable to Non-Slice customer loads. In this case, the Balancing Augmentation Adjustment is a debit to the Composite cost pool and an equal credit to the Non-Slice cost pool.

This condition causes the sum of the Load Shaping billing determinants to be negative. The Balancing Augmentation Load Adjustments to the Composite and Non-Slice cost pools are calculated as the greater of (1) the sum of the Load Shaping billing determinants for each fiscal year and (2) the avoided augmentation amount for each fiscal year. The result is multiplied by the augmentation price for the respective fiscal year.

3.1.3.3.3 Changes to the Tier 1 System During the Applicable 7(i) Ratesetting Process

This third condition occurs when the forecast of Tier 1 System output is updated from the Tier 1 System forecast in the RHWM Process. Any difference resulting from the updated calculation of the Tier 1 System output in the rate proceeding will cause either a cost or a credit to be included in the Balancing Augmentation Load Adjustment. The cost or credit is included as an addition to the Balancing Augmentation Adjustment rather than in the Balancing Power Purchase costs computed in RevSim. Movements in the updated Tier 1 System output will increase or decrease on an annual-average basis the amount of Augmentation required, which is considered Balancing Power Purchases under the TRM. RevSim computes Balancing Power Purchase costs after load-resource balance has been achieved under critical water. *See* TRM, BP-12-A-03, § 3.3. If the size of the Tier 1 System output increases relative to the RHWM Process Tier 1 System output, the Non-Slice cost pool will receive a credit for this additional anticipated energy. Alternatively, if the size of the Tier 1 System output decreases, the Non-Slice cost pool will be charged for the reduction in anticipated energy. Customers purchasing the Slice/Block product receive either more or less energy in anticipated Slice-resource deliveries and therefore are compensated by these equal and offsetting costs/credits to the Composite cost pool. *See* Documentation Table 2.5.6.

The Balancing Augmentation Load Adjustments to the Composite and Non-Slice cost pools are calculated as the greater of the sum of the difference in the Tier 1 System between the rate proceeding and the RHWM Process for each fiscal year or the avoided augmentation amount for each fiscal year. The result is multiplied by the augmentation price for the respective fiscal year.

3.1.4 Rate Design Adjustment Made Between Tier 1 and Tier 2 Cost Pools

The Tier 2 Overhead Adjustment credits the Composite cost pool for the overhead costs charged to the Tier 2 cost pools. Each of the Tier 2 cost pools includes an Overhead Cost Adder, which reflects a proportionate share of BPA's total overhead costs. *See* § 3.1.7.1. The Tier 2 Overhead Adjustment credited to the Composite cost pool is equal to the sum of the Overhead Cost Adders charged to all of the Tier 2 cost pools. The inputs to the Tier 2 Overhead Adjustment for FY 2016–2017 are shown in Documentation Table 3.2.

3.1.5 PFp Tier 1 Billing Determinants

3.1.5.1 Tier 1 Cost Allocator (TOCA)

The majority of BPA's costs to be collected through PF rates are allocated among customers through the TOCA. The TOCA is the customer-specific billing determinant used to collect the costs allocated to the Composite cost pool. A TOCA is calculated for each fiscal year of the rate period for each PFp customer. Each customer's annual TOCA is calculated as a percentage by dividing the lesser of an individual customer's RHWM or its Forecast Net Requirement by the total of the RHWMs for all PFp customers. The TOCA is a percentage rounded to five decimal places, *i.e.*, seven significant digits.

The Forecast Net Requirement and RHWM for the individual customer and the sum of RHWMs for all customers are expressed in average annual megawatts and rounded to three decimal places. The total of the RHWMs for all customers is shown in PRS Table 1, and the sum of TOCAs used for FY 2016–2017 is shown in Documentation Table 2.5.6.3.

3.1.5.2 Non-Slice TOCA

The Non-Slice TOCA is the billing determinant used to collect the costs allocated to the Non-Slice cost pool. A Non-Slice TOCA is calculated for each PFp customer for each year of the rate period. The Non-Slice TOCA is equal to a customer's TOCA if the customer is purchasing the Load Following or Block product. The Non-Slice TOCA for customers purchasing the Slice/Block product is computed as the difference between the customer's TOCA and its Slice percentage. The Non-Slice TOCA percentage is rounded to five decimal places. The forecast sum of Non-Slice TOCAs used for FY 2016–2017 is shown in Documentation Table 2.5.6.3.

3.1.5.3 Slice Percentage

The Slice percentage is the billing determinant used to collect the costs allocated to the Slice cost pool. A Slice percentage is calculated for each year of the rate period for each PFp customer purchasing the Slice/Block product. The initial Slice percentages are in Exhibit J of each Slice customer's CHWM contract. These percentages can be adjusted each year pursuant to TRM section 3.6 and reflected in Exhibit K of the customer's CHWM contract. The Slice percentage is rounded to five decimal places.

3.1.5.4 Load Shaping Billing Determinant

The billing determinant for the Load Shaping charge reflects the difference between a customer's actual load served at Tier 1 rates and the customer's annual load reshaped into the monthly/diurnal shape of RHWM Tier 1 System Capability (System Shaped Load). The Load Shaping billing determinant can have either a positive or a negative value. Pursuant to the TRM, a Load Following customer's Above-RHWM load that is forecast to be less than 8,760 MWh that is not served with Non-Federal Resources will be served by BPA at the Load Shaping rate and is reflected in this billing determinant. *See* Tiered Rate Methodology, BP-12-A-03, at 54.

A customer's System Shaped Load is calculated as the RHWM Tier 1 System Capability (*see* section 1.4) for each of the 24 monthly/diurnal periods of the fiscal year multiplied by the customer's Non-Slice TOCA. The Load Shaping billing determinants are calculated as the amount of a customer's monthly/diurnal electric load (measured in kilowatthours) to be served at Tier 1 rates minus the customer's System Shaped Load for the same monthly/diurnal period.

Monthly/Diurnal RHWM Tier 1 System Capability. The TRM prescribes that the monthly/diurnal shape of the RHWM Tier 1 System Capability will be used to compute the System Shaped Load for purposes of computing Load Shaping billing determinants. The System Shaped Load is not updated if the Tier 1 System output is updated in the rate proceeding. The shape is computed to be constant across both years of the rate period and is the average of each year's respective monthly/diurnal megawatthour amount. In a rate period that does not include a leap year, there will be 24 monthly/diurnal amounts for the RHWM Tier 1 System Capability specified in the GRSPs. In a rate period that includes a leap year, there will be 26 amounts, a unique value for each February to account for the additional day. *See* GRSP II.V.

3.1.5.5 Demand Billing Determinant

The Demand billing determinant applies to customers purchasing the Load Following product, the Block product, and the Block portion of the Slice/Block product. TRM sections 5.3.1 to 5.3.5 contain a detailed explanation of how to calculate the Demand billing determinant. The following is a summary of the TRM explanation.

Four quantities are used in calculating a PFp customer's Demand charge billing determinant: (1) the Tier 1 Customer's System Peak (CSP); (2) the average amount of a customer's electric load (measured in average kilowatts) that was served at Tier 1 rates during the Heavy Load

Hours of a month; (3) the customer's Contract Demand Quantity (CDQ, expressed in kilowatts); and (4) any applicable Super Peak Credit as specified in a customer's CHWM contract.

The Demand billing determinant is determined by measuring a customer's CSP and then subtracting the other three quantities. The Demand billing determinant calculation can never result in a negative billing determinant. That is, if the calculation results in a value less than zero, the billing determinant is deemed to be zero.

Tier 1 CSP is equal to a customer's maximum Actual Hourly Tier 1 Load (measured in kilowatts) during the Heavy Load Hours of a month.

Twelve CDQs are specified for each PFp customer in the customer's CHWM contract.

The Super Peak Credit will be determined pursuant to a customer's CHWM contract. The Super Peak Period for FY 2016–2017 is defined in GRSP III.B.

There are two possible adjustments that may be made to a customer's Demand billing determinant. The first is an adjustment to offset anomalous recovery load peaks that occur after a customer has had power restored to its service territory following a weather-related system outage or other extreme peak event. The second is an adjustment to offset extreme load changes that have severely adversely affected a customer's load factor. GRSP II.D includes the calculations for applying these adjustments, applicable qualifying criteria, and notice requirements.

3.1.6 PFp Tier 1 Rates

3.1.6.1 Tier 1 Customer Rates

Rates for the Composite, Non-Slice, and Slice customer charges are expressed as dollars per one percentage point of billing determinant (TOCA, Non-Slice TOCA, or Slice percentage, respectively). Each of the three rates is calculated by dividing the total costs allocated to each cost pool by the sum of the respective forecast billing determinants. The quotient of that calculation is then divided by 12 to yield a monthly rate per one percent of the applicable billing determinant.

The monthly rates for each of the Tier 1 cost pools are shown in Documentation Table 2.5.6.3.

3.1.6.2 Tier 1 Load Shaping Rates

The PFp rate design includes 24 Load Shaping rates (two diurnal periods—HLH and LLH—for each of 12 months). The Load Shaping rates are set equal to the rate period average marginal cost of power for each monthly/diurnal period as determined in the Power Risk and Market Price Study, BP-16-FS-BPA-04, section 2.4. *See also* Documentation Table 3.3.

3.1.6.2.1 Load Shaping True-Up

The Load Shaping True-Up is an adjustment to the Load Shaping charge that is necessary to ensure each customer pays a Tier 1 rate for purchases of energy that are less than its RHWM. At the end of each fiscal year, for each Load Following customer BPA will calculate whether a true-up of the Load Shaping charge applies. The Load Shaping Charge True-Up Adjustment applies to a Load Following customer when either its TOCA Load or its Actual Annual Tier 1 Load is less than its RHWM. The Load Shaping True-Up rate is the difference between (1) the system-weighted average of the Load Shaping rates and (2) the Composite Customer rate plus the Non-Slice Customer rate, converted to mills per kilowatthour. The process for calculating the Load Shaping True-Up rate is shown in TRM section 5.2.4., and the rate is specified in GRSP II.L.

Special Implementation Provision for Load Shaping True-Up. The Load Shaping True-Up Adjustment (GRSP II.L) includes special implementation provisions that apply if two conditions are met: (1) a customer has Above-RHWM load; and (2) the customer has unused RHWM greater than zero. If these conditions are met, the customer may be eligible for an additional Load Shaping True-Up credit. The amount of the additional Load Shaping True-Up credit will depend on a second calculation.

This special implementation provision was originally designed to solve a transitional implementation issue caused by setting Above-RHWM load based on a forecast different from that used to determine a customer's TOCA. This provision has a longer-term application, however, because Above-RHWM load is determined in the RHWM Process (prior to the Initial Proposal of each rate proceeding), and the calculation of a customer's TOCA occurs in the Final Proposal. A consequence of using forecasts prepared at different times is the possibility that a customer has both Above-RHWM load and unused RHWM. This cannot happen if the same forecast is used to set both Above-RHWM load and customers' TOCAs.

When both conditions above are met, the amount of additional Load Shaping True-Up credit a customer may be eligible for is based on the following calculation. First, if the Annual Deviation calculation of the Load Shaping Charge True-Up is negative or equals zero, and the absolute value of the Annual Deviation is less than the customer's Above-RHWM load, then the additional credit is equal to the Load Shaping True-Up rate multiplied by the smallest of (1) the customer's Above-RHWM load, (2) the Above-RHWM load less the absolute value of the Annual Deviation amount, or (3) the Above Forecast amount. Second, if the Annual Deviation calculation of the Load Shaping Charge True-Up is positive and the Annual Deviation amount is less than the Above Forecast amount, then the additional credit is equal to the Load Shaping True-Up rate multiplied by the lesser of (1) the customer's Above-RHWM load or (2) the Above Forecast amount minus the Annual Deviation amount.

3.1.6.3 Tier 1 Demand Rates

Demand rates are based upon the annual fixed costs (capital and O&M) of the marginal capacity resource, an LMS100 combustion turbine, as determined by the Northwest Power and Conservation Council's Microfin model 15.0.1. The Microfin model is used to obtain an estimate for the nominal all-in capital costs of an LMS100 with a 2016 in-service date. The all-in capital cost under these specifications is $1,011/kW. *See* Documentation Table 3.4.

The projected debt payment on the $1,011/kW fixed capital costs is estimated at $63.61/kW/yr, based on a cost of debt of 4.71 percent financed over 30 years. The plant is assumed to be owned by a publicly owned utility with BPA-backed bonds. The cost of debt is estimated with BPA's FY 2016 Third-Party Tax-Exempt 30-Year Borrowing Rate Forecast. *See* FY 2015 Interest Rate and Inflation Forecast memo in the Power Revenue Requirement Study Documentation, BP-16-FS-BPA-02A, § 6.

The cost of fixed O&M included in the Demand rate calculation is obtained from the Microfin model. The calculation of the Demand rate uses the Microfin model's 2012 estimate of $11/kW/yr escalated to 2016 and 2017 dollars using the 2010 to 2014 average (5-year) rate of 1.61 percent calculated from the Implicit Price Deflators from the U.S. Bureau of Economic Analysis. The two-year average annual cost for fixed O&M is $11.81/kW/yr.

Insurance and fixed fuel are also included in the calculation of the Demand rate. The average annual insurance cost of $2.44/kW/yr is calculated based on 0.25 percent of the mid-year assessed value obtained from the Council's Microfin model. The fixed fuel cost assumed in the Demand rate calculation is $40.40/kW/yr. The fixed fuel cost is estimated using Microfin's vintaged heat rate of 8,541 Btu/kWh applied to the average of the existing and new Pacific Northwest East (PNWE) fixed fuel costs for the applicable fiscal year.

The average annual expense is $118.59/kW. This annual value is shaped into the 12 months of the year using the shape of the Load Shaping rates, resulting in Demand rates specific to each month. *See* Documentation Table 3.4 and the BP-16 Power Rate Schedules, *e.g.*, Schedule PF-16, § 2.1.2.1.

3.1.6.4 PFp Tier 1 Equivalent Rates

The PFp Tier 1 Equivalent rates consist of 12 HLH Energy rates, 12 LLH Energy rates, and 12 Demand rates. The PFp Tier 1 Equivalent Energy rates are equal to the Load Shaping rates less a single $/MWh value. The single $/MWh value scales the Load Shaping rates to a level at which the PFp Tier 1 Equivalent Energy rates, in conjunction with the demand revenue, would collect the Tier 1 revenue requirement allocated to the PFp Non-Slice loads (the Composite cost pool plus the Non-Slice cost pool). This single $/MWh value is equivalent to the Load Shaping True-Up rate. This calculation is shown in Documentation Table 2.5.8.5. The Demand rates are equal to the Tier 1 Demand rates. *See* GRSP II.Q.

3.1.6.5 PFp Slice Billing Adjustment

The PFp Slice Billing Adjustment is a charge to the November 2015 power bill for customers who had CHWM Slice/Block contracts during FY 2012–2015. This adjustment is based on the Slice/Block customers' shares of the Slice percentage share of $3.542 million per year in

"Accrual Revenues" associated with the WNP-3 Settlement included in the Non-Slice cost pool in BP-12 and BP-14. The Slice Billing Adjustment results from the misallocation of minimum required net revenue (MRNR) costs associated with revenues from the 1998 WNP-3 settlement with PGE. All of the cash was received in 1998, and the revenue associated with this settlement is recognized by BPA as an annual credit of $3.542 million from 1998 to 2019. In BP-12 and BP-14, the annual credit was allocated to the Composite cost pool, but the non-cash MRNR cost item was allocated to only the Non-Slice cost pool. Since the annual credit was shared among all customer classes through the Composite cost pool, and the non-cash cost item was allocated only to Non-Slice loads for MRNR computation purposes, a cost shift from the Composite cost pool to the Non-Slice cost pool occurred. The settlement predated the creation of the Slice product, and therefore the funds associated with the settlement contributed to the interest credit on the financial reserves balance for the Composite cost pool. The non-cash cost item associated with the settlement should have been allocated to the Composite cost pool to compute MRNR. The PFp Slice Billing Adjustment corrects this unintended cost shift between the Composite and Non-Slice Cost Pools that occurred in setting the BP-12 and BP-14 rates. The revenue from the billing adjustment is included in Documentation Table 2.3.1.5 as "Slice Billing Adjustment" and Table 2.5.6.2 under "FPS Revenues not classified as Obligations in TRM." Each applicable Slice/Block customer's billing adjustment is summarized in Documentation Table 3.5. The misallocation of costs is corrected in Documentation Tables 2.3.1.4 and 2.5.1.

3.1.6.6 Conservation Cost and Credits Associated with Post-2011 Energy Efficiency Implementation

BPA's Post-2011 Energy Efficiency Review Process led to a new program to support conservation acquisitions during the Regional Dialogue contract period. This new program is the Large Project Program (LPP), which is designed to be revenue neutral to non-participating power customers. LPP financing costs are included in the aggregate debt service in the revenue requirement, and equal and offsetting revenue credits are included in ratemaking. *See* Documentation Table 2.3.1.5.

3.1.7 PFp Tier 2 Cost Pool

There are four Tier 2 cost pools: the Short-Term cost pool, the Load Growth cost pool, the VR1-2014 cost pool, and the VR1-2016 cost pool. Costs allocated to the aggregate Tier 2 cost pool thus are further allocated to these four cost pools. For the rate period, those allocated costs are either the actual costs associated with the flat-block energy purchases for those rate pools at the transacted amounts and prices, or the forecast augmentation rate, when applicable. Costs for the Tier 2 Overhead Adjustment and scheduling services are added to these cost pools as described in the following sections. Remarketing credits are applied to each applicable cost pool as described in section 3.1.7.3.2.

3.1.7.1 Tier 2 Overhead Cost Adder

TRM section 6.3.3 describes an Overhead Cost Adder to be included as part of the Tier 2 rates. The overhead cost components used to calculate the Tier 2 Rate Overhead Cost Adder are listed in Documentation Table 3.2. The rate period total of these overhead costs is divided by BPA's total forecast of revenue-producing energy sales (PFp, IP, NR, FPS, Downstream Benefits and Pumping Power, Pre-Subscription, Generation Inputs for Ancillary and Other Services Revenue, and Secondary sales). The result is a $1.30/MWh adder on average for the rate period. The $/MWh value in each year is multiplied by the amount of planned sales in each year for each Tier 2 alternative (Short-Term, Load Growth, VR1-2014, and VR1-2016) to produce a dollar value for the Overhead Cost Adder included in each cost pool for each year. The Tier 2 Overhead Cost Adder provides the revenue credit to the Composite cost pool (called Tier 2 Overhead Adjustment). *See* § 3.1.4. The specific cost and sales values used in these calculations are shown in Documentation Table 3.6.

3.1.7.2 Tier 2 Transmission Scheduling Service Cost Adder

A cost for Transmission Scheduling Service (TSS) is added to each Tier 2 cost pool. A TSS Adder is calculated by dividing the operations scheduling costs for the rate period by the total megawatthours actually scheduled in FY 2013 and FY 2014 to produce a yearly $/MWh value. Inputs to this calculation are shown in Documentation Table 3.8. This value is multiplied by the amount of planned Tier 2 sales in each year for each Tier 2 alternative (Short-Term, Load Growth, VR1-2014, and VR1-2016) to produce the annual cost for the TSS Cost Adder included in each cost pool for each year. The Tier 2 TSS Cost Adder is one of the credits to the Composite cost pool summed in the Resource Support Services Revenue Credit. *See* § 3.1.2.1. The calculated costs assigned to each cost pool in each year are shown in Documentation Tables 3.9, 3.10, 3.11, and 3.12.

3.1.7.3 Tier 2 BPA Market Purchases

BPA made three purchases for Tier 2 rate service for the FY 2016–2017 rate period. Two were made in FY 2012, and one was made in FY 2013. The costs of the FY 2012 purchases were assigned to the Load Growth and Vintage VR1-2014 Tier 2 cost pools at the time of purchase. The cost of the FY 2013 purchase was assigned to the Vintage VR1-2016 Tier 2 cost pool. Any remaining amount of need for these cost pools and for the Short-Term cost pool after the purchases are allocated is valued at the forecast augmentation price. The average megawatt purchase amounts for each rate pool and their associated power purchase prices are summarized in Documentation Table 3.13.

3.1.7.3.1 Reallocated Power from the Load Growth Rate Cost Pool

When power purchased for the Load Growth rate pool exceeds the rate pool's Tier 2 load obligation for the rate period as determined in accordance with the RHWM Process (including the real power losses to deliver the power to the purchasers), the power in excess of the cost pool's load is reallocated to another Tier 2 cost pool(s) pursuant to TRM section 3.4. This allocation is done on a pro rata basis based on the outstanding need across the pools.

For ratemaking purposes, this reallocation of power is at BPA's forecast augmentation price for the rate period. TRM § 3.4. The rates are computed based on both the augmentation price for each year of the rate period and the purchase price of the reallocated power from the Load Growth customer pool. The revenues from such reallocation are credited to the Load Growth cost pool. The cost differential between the power purchase cost and the price associated with the reallocated power is removed from the Load Growth rate and charged to a set of Load Growth rate customers through a Load Growth Rate Customer Charge, described in section 3.1.12 below.

3.1.7.3.2 Reallocated Power from CHWM Contract Section 10 Remarketing

When power purchased for the Tier 2 rate pool exceeds Above-RHWM loads, for some purchasers BPA remarkets the excess amount. Pursuant to TRM section 6.4 and section 10.4 of the CHWM contract, BPA remarkets the Tier 2 rate purchase amount in excess of the customer's need and credits the proceeds to that customer.

Similarly, there are customers with Specified Resources to which Diurnal Flattening Service (DFS) applies that are in excess of a Customer's Above-RHWM load. Pursuant to section 10.5 of the CHWM contract, BPA must remarket the amounts of non-Federal resources with DFS in the same manner as it remarkets Tier 2 rate purchase amounts.

The revenues from such reallocations are credited to the individual customers, as required under the CHWM contract and the TRM and as described in sections 3.1.11 and 3.1.15.2.5 below. Documentation Table 3.14 summarizes the sources of power for meeting the various Tier 2 loads. It includes both executed and forecast purchases, remarketed power from other Tier 2 cost pools, and remarketed power from non-Federal resources with DFS.

3.1.7.4 Tier 2 Risk Analysis

The risk analysis for Tier 2 rate service is addressed in the Power Risk and Market Price Study, BP-16-FS-BPA-04, section 4.3. Consistent with that discussion, no risk mitigation treatment is added to the Tier 2 cost pools to cover risks in the FY 2016–2017 rate period.

3.1.8 PFp Tier 2 Billing Determinants

The Tier 2 billing determinant is equal to each customer's commitment to purchase from BPA all or a portion of the customer's Above-RHWM load. Each customer's Tier 2 rate service amount is contractually established for FY 2016–2017. The totals for all customers (by Tier 2 alternative) are summarized in Documentation Table 3.15.

3.1.9 Tier 2 Rates

Based on the annual average megawatt load obligations for each Tier 2 rate alternative (Short-Term, Load Growth, VR1-2014, and VR1-2016) in each year and the costs for each cost pool in each year, Tier 2 rates are calculated as summarized in Documentation Tables 3.9, 3.10, 3.11, and 3.12. Each rate is calculated by dividing the annual costs allocated to the specific Tier 2 cost pool by the billing determinants in that same fiscal year. A specific Tier 2 rate in each year for each Tier 2 rate alternative is necessary because there are different sets of customers associated with each rate, different costs from the separate purchases, different allocations to Tier 2 cost pools, and different surplus/deficit calculations. Pursuant to the TRM, a Load Following customer's Above-RHWM load that is forecast to be less than 8,760 MWh and that is not served with Non-Federal Resources will be served at Tier 2 rates set equal to the Load Shaping rate.

3.1.9.1 Tier 2 Rate Transmission Curtailment Management Service (TCMS) Adjustment

The Tier 2 rate schedule includes an adjustment for TCMS-related costs. This adjustment will occur if a transmission event (in the form of either a planned transmission outage or a transmission curtailment) has occurred along the transmission path between Mid-C and the BPA point of delivery for the market purchases allocated to the Tier 2 cost pools. The adjustment is described in GRSP II.U.4.

3.1.10 Calculating Charges to Reduce Tier 2 Purchase Amounts

3.1.10.1 Tier 2 Purchase Amount Reductions for Vintage Rate Service

Section 2.3.1.1 of Exhibit C of the Load Following CHWM contract provides customers with an opportunity to reduce their purchase amounts supplied by BPA at the Tier 2 Short-Term rate and replace them with service from BPA at a Tier 2 Vintage rate if one is offered. For customers making this election, BPA will levy charges to cover costs that BPA is obligated to pay and is not able recover through other transactions. Section 2.3.1.4 of the CHWM contract states that BPA shall determine the costs, if any, to be collected from such charges during the 7(i) process that establishes the applicable Tier 2 Vintage rate.

3.1.10.2 Tier 2 Purchase Amount Reductions for Service with Non-Federal Resources

Section 2.4.2 of Exhibit C of the Load Following CHWM contract provides customers with an opportunity to reduce their purchase amounts from BPA at the Tier 2 Short-Term rate and replace them with Unspecified Resource Amounts if the customer provides BPA notice by October 31 prior the rate proceeding. This notice deadline was postponed until November 30, 2014, for the BP-16 rate period due to the extension of the RHWM Process. If a customer makes this election, BPA may levy charges upon that customer to recover costs that BPA is obligated to pay and is not able to recover through other transactions. Section 2.4.2.1 of the contract states that BPA shall determine the costs, if any, to be collected from such charges during the

7(i) process following a customer's notice to reduce its Tier 2 rate purchase amount. No customers provided BPA notice that they were reducing their purchase amounts for this rate period.

3.1.11 Tier 2 Remarketing for Individual Customers

3.1.11.1 Tier 2 Remarketing for Load Following Customers

Section 10 of the CHWM contract states that the customer may elect to have BPA remarket its Tier 2 rate purchase amount in the event its Above-RHWM load as forecast for an upcoming rate period year is less than the sum of its Tier 2 rate purchase amounts and New Resource amounts. Notice of such election must be provided by October 31 of the year of a rate case initial proposal for Load Following customers. Due to the extended RHWM Process prior to the BP-16 rate case, this election was adjusted to November 30, 2014.

3.1.11.2 Tier 2 Remarketing for Slice/Block Customers

Section 10 of the CHWM contract states that a customer may elect to have BPA remarket its Tier 2 rate purchase amount in the event its Forecast Net Requirement for the first fiscal year of an upcoming rate period is less than the sum of its RHWM and Tier 2 rate purchase amounts. Notice of such election must be provided by August 31 of the applicable fiscal year.

3.1.11.3 Calculating the Remarketed Tier 2 Proceeds for Load Following and Slice/Block Customers

Section 6.4 of the TRM states that if BPA remarkets a customer's Tier 2 purchase obligation pursuant to the CHWM contract, BPA will credit the proceeds from the remarketing (net of any remarketing costs) to such customer. The customer must continue to pay for the entire purchase at the appropriate Tier 2 rate. The remarketed Tier 2 proceeds are computed for Load Following customers using (1) the remarketed amount of Tier 2 service (in megawatthours) plus real power losses and (2) either the forecast augmentation price for the rate period or the actual price BPA paid for the power it purchased to meet its remaining Tier 2 need in FY 2016–2017. After notice is provided by a Slice/Block customer, the remarketed Tier 2 proceeds will be computed for that customer using (1) the remarketed amount of Tier 2 service (in megawatthours) plus real power losses and (2) the flat annual equivalent market price forecast for the applicable fiscal year plus any additional costs incurred by BPA in purchasing power from other entities. The annual remarketing proceeds for each customer will be divided by 12 to compute a flat monthly credit that will be applied to the customer's bill. Each applicable Load Following customer's forecast of monthly remarketed Tier 2 proceeds amount is summarized in Documentation Tables 3.16 and 3.17.

3.1.12 Load Growth Rate Customer Charge

BPA will apply a charge to the bills of Load Growth customers with an Above-RHWM load greater than zero and less than 8,760 MWh, as calculated in the RHWM Process. As described in section 3.1.7.3 above, BPA purchased power in excess of FY 2016 and FY 2017 Load Growth rate customer need. This excess power will be allocated to the other Tier 2 cost pools at the price BPA pays for purchases made to meet the remaining Tier 2 load obligation plus losses. In this rate period, the price BPA paid for the power is greater than the remarketing price. The difference is allocated to the Load Growth customers in the form of a customer charge using their Above-RHWM load (if it was computed in the RHWM Process to be greater than zero and less than 8,760 MWh) as the cost allocator. The cost differential plus losses is $516,489 in FY 2016 and $575,371 in FY 2017. Each applicable Load Growth customer's forecast customer charge is summarized in Documentation Table 3.18.

3.1.13 PFp Irrigation Rate Discount

The Irrigation Rate Discount (IRD) is a discount to the PFp Tier 1 rates for eligible irrigation load served by a customer. The discount will appear as a credit on customer bills as an offset to the charge of eligible irrigation load at Tier 1 rates. This discount is available to eligible loads during May, June, July, August, and September during the BP-16 rate period. *See* GRSP II.K.

3.1.13.1 Irrigation Rate Discount Calculation

The TRM establishes the method for calculating the IRD. The process begins with a fixed Irrigation Rate Mitigation Program (IRMP) percentage of 37.06 percent. *See* TRM, BP-12-A-03, § 10.3, and BP-12 Power Rate Study Documentation, BP-12-FS-BPA-01A, Tables 3.14 and 3.15.

The IRMP percentage is multiplied by the sum of the forecast revenue that irrigation loads will pay through the Composite Customer Charge, the Non-Slice Customer Charge, and the Load Shaping Charge, adjusted for any applicable Low Density Discount, divided by the sum of the irrigation loads (expressed in megawatthours) to derive a dollars per megawatthour discount. The applicable Low Density Discount is calculated as the weighted average Low Density Discount of eligible irrigation customers, weighted with eligible irrigation loads. *See* Documentation Table 3.20.

Forecast revenue for irrigation loads will be calculated using an IRD TOCA derived by dividing the sum of the irrigation loads (expressed in average megawatts) by the sum of all RHWMs. The IRD TOCA will be applied consistent with TRM section 5 for calculation of forecast irrigation revenues from the Composite Customer Charge, the Non-Slice Customer Charge, and the Load Shaping Charge. The calculation is shown on Documentation Tables 2.3.3.1 – 2.3.3.3.

3.1.13.2 Irrigation Rate Discount Bill Credit

The irrigation credit available to a customer with eligible irrigation load is equal to the monthly irrigation load set forth in Exhibit D of the customer's CHWM contract multiplied by the IRD. The amount of irrigation credit the customer will receive is based on the lesser of a customer's Tier 1 energy purchase or its eligible irrigation load amounts in the customer's CHWM contract.

3.1.13.3 Irrigation Rate Discount True-Up

At the end of each irrigation season, customers with eligible irrigation load will send BPA their measured May-through-September irrigation load amounts. If BPA determines that the measured irrigation load amounts are less than the eligible irrigation load amounts set forth in Exhibit D of the customer's CHWM contract, then the purchaser shall reimburse BPA for the excess IRD credits. Excess IRD credits will be calculated as the IRD rate multiplied by the difference between the contract irrigation load and the measured irrigation load.
See GRSP II.K.3.

3.1.14 PFp Melded Rates (Non-Tiered Rate)

The PF Melded rate design applies to purchases by public bodies, cooperatives, and Federal agencies pursuant to power sales contracts other than CHWM contracts. No sales under the PF Melded rate are forecast during the rate period, FY 2016–2017.

Melded PF Public rates are included in the PF rate schedule, section 3. The PFp Melded rates consist of 12 HLH Energy rates, 12 LLH Energy rates, and 12 Demand rates. The PFp Melded Energy rates are equal to the PFp Load Shaping rates less a single $/MWh value. The single $/MWh value adjusts the Load Shaping Rates so that the PFp Melded Energy rates, in conjunction with the demand revenue, do not collect more or less revenues than the Tier 1 and Tier 2 revenue requirement allocated to the PFp loads. The $/MWh value is the PFp Melded

Equivalent Energy Scalar calculation of the scalar is shown in Documentation Table 2.5.8.2. The applicable Demand rates are equal to the PFp Tier 1 Demand rates.

3.1.15 PFp Resource Support Services

BPA offered customers access to RSS and related services for their variable, non-dispatchable non-Federal resources, in accordance with the CHWM contract. The related services include Transmission Scheduling Service and Transmission Curtailment Management Service. In general, these services are designed to financially convert a variable, non-dispatchable resource into a flat annual block of power or the specified monthly/diurnal resource shape found in Exhibit A of the customer's CHWM contract. Resource Remarketing Service (RRS) is an additional related service that will be provided during the BP-16 rate period.

RSS is also applied to Federal resource acquisitions to make them financially equivalent to a flat block, if necessary. *See* TRM, BP-12-A-03, § 8. The cost of Klondike III, a wind plant, is assigned to Tier 1 Augmentation in the Composite cost pool. Tier 1 Augmentation is assumed to be in the shape of an annual flat block purchase for ratemaking purposes. *See id.* § 3.5. Because Klondike III's generation is variable and non-dispatchable in nature, certain RSS rate design components apply to Klondike III, and the resulting costs are allocated to the Composite cost pool. These costs are described below.

Costs for RSS are not allocated to the Tier 2 cost pools because there are no variable, non-dispatchable resources assigned to the Tier 2 cost pools. Costs for TSS are allocated to the Tier 2 cost pools, as described in section 3.1.7.2 above. Costs for TCMS events associated with Tier 2 rate service are recovered through the Tier 2 Rate TCMS Adjustment, described in section 3.1.9.1 above.

3.1.15.1 RSS Rates

RSS rates are included in the PF and FPS rate schedules. The RSS rates relevant to the PFp rates include Diurnal Flattening Service energy and capacity rates, Grandfathered Generation Management Service rates, Resource Shaping rates and adjustment, Secondary Crediting Service shortfall and secondary energy rates, and Secondary Crediting Service Administrative Fee rate. The RSS rates relevant to the FPS rate include Forced Outage Reserve Service energy and capacity rates, the TSS rate, the TCMS rate, and RRS. In total, about $3 million of forecast RSS and TSS-related revenue credits are applied annually to the Tier 1 cost pools. *See* Documentation Tables 3.1 and 3.6.

3.1.15.2 RSS Diurnal Flattening Service, Resource Shaping Charge, and Resource Shaping Charge Adjustment

3.1.15.2.1 Diurnal Flattening Service

DFS is an optional service that financially converts the output of a variable, non-dispatchable resource into the equivalent of a flat amount of power within each diurnal period of a month. When DFS charges are coupled with Resource Shaping Charges, the variable output of a generating resource is financially converted to a flat annual block of power. BPA selected a flat annual block of power as the benchmark shape that is compared to new non-Federal resources and Tier 2 purchases. DFS will apply to the non-Federal resource the customer is applying to its load and any portion of the resource remarketed by BPA.

The RSS module of RAM calculates a unique set of rates and charges for each resource to which DFS is applied. Included in Documentation Table 3.21 are the final rates and charges calculated for the customers that have requested DFS for their resources. PF-16 rate schedule sections 5.1 and 5.2 describe the general rate application of the DFS-related charges. The GRSPs include the calculations for the DFS capacity charges, DFS energy charges, and Resource Shaping charges for the resources to which DFS is applied. *See* GRSP II.U.

Briefly, DFS charges include the following elements:

- A DFS capacity charge based on the PFp Tier 1 Demand rate applied to the difference between the calculated firm capacity of the resource and the planned average HLH generation of the resource. This charge reflects the costs of reserving an amount of capacity to smooth the variable generation of a resource into a flat block of power.
- A DFS energy charge based on the potential cost of storing and releasing power using a resource capable of storing energy (pumped storage) to balance the hourly shape of the resource to which DFS is applied. This charge reflects the costs of energy storage to smooth the hourly generation variation into a flat monthly/diurnal block of power.

When DFS is applied to a resource, other charges must be added to the DFS charges to complete the financial conversion to a flat annual block of power. These include the following elements:

- The Resource Shaping charge, based on the Resource Shaping rates (which are equal to the PFp Tier 1 Load Shaping rates), to financially convert the resource amounts that have been flattened on a monthly/diurnal basis into a flat annual block of power.
- A Resource Shaping Charge Adjustment, based on the Resource Shaping rates, to correct for differences in the planned generation used to calculate the Resource Shaping charge and the actual (metered or scheduled) generation.

3.1.15.2.2 DFS Capacity Charge

Unless stated otherwise, the resource amounts used in the calculations shown below are either (1) generation amounts specified in the customer's CHWM contract Exhibit A (Exhibit A amounts) or (2) planned generation amounts based on hourly generation from the most recent historical year specified in the customer's CHWM contract Exhibit D (Exhibit D amounts).

DFS Capacity Rate. The rates used to calculate the DFS Capacity Charge are the monthly PFp Tier 1 Demand rates.

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

Monthly Firm Capacity. The RSS module of RAM calculates monthly firm capacity amounts for each resource. This calculation represents the lowest level of historical generation in a HLH period for each month after accounting for planned and forced outages. The firm capacity of a resource is calculated as the percentile equal to the forced outage rating calculated from the historical monthly HLH generation levels. In other words, a resource with a 5 percent forced outage rating would have a firm capacity amount equal to the 5th percentile of the hourly historical generation amounts for the HLH period of a month.

The billing determinant also includes a planned outage adjustment. If the historical hourly data reflects an outage that was planned, the model does a second calculation of the monthly firm capacity amount. This test runs the same calculation as above but calculates the value approximately equal to the forced outage percentile of an hourly sample that does not include the hours that were identified as a planned outage. If the number of planned outage hours is less than 25 percent of the HLH in the month, no further adjustments are made to the value calculated by the planned outage calculation of firm capacity. If the number of planned outage hours is equal to 25 percent of the HLH in the month but less than 75 percent of the hours in the month, the planned outage adjusted firm capacity value is reduced by multiplying it by one minus the percentage of planned hours in the month. If the number of planned outage hours in the month is equal to or greater than 75 percent of the HLH in the month, the firm capacity of the resource in that particular month is set to zero.

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

(1) the sum of the monthly DFS Capacity rates multiplied by the monthly DFS billing determinants

or

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

The result is then divided by 12 to calculate a flat monthly charge that will be specified in Exhibit D of the customer's CHWM contract. Documentation Table 3.21 shows the individual DFS capacity charges that are calculated for the individual resources to which DFS is applied.

3.1.15.2.3 DFS Energy Charge

DFS Energy Rate. A unique DFS energy rate is developed for each resource to which DFS is applied. The purpose of this rate is to reflect the potential cost of storing and releasing energy to offset the hourly variability of the resource's Exhibit D amounts. The RSS module of RAM calculates the DFS energy rate for each resource. Generally, for each monthly/diurnal period in a year, the sum of planned generation in excess of average monthly/diurnal Exhibit D 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 from the Exhibit D amounts to calculate the DFS Energy rate.

DFS Energy Billing Determinant. The DFS 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. For resources within the BPA balancing authority area, transmission curtailments associated with Dispatcher Standing Order(s) and reliability protocols related to BPA's balancing services offered through the Ancillary and Control Areas Services rates will be treated as reduced scheduled amounts when calculating the actual generation for such resources.

DFS Energy Charge. The DFS energy charge is the product of multiplying the DFS energy rate by the DFS energy billing determinant for each month. Documentation Table 3.21 shows the DFS energy rates that are calculated for the individual resources to which DFS is applied. GRSP II.U.1.(a) includes the formula for calculating the DFS energy charges for the individual resources to which DFS is applied.

3.1.15.2.4 Resource Shaping Charge

Resource Shaping Rate. The monthly/diurnal Resource Shaping rates are equal to the PFp Tier 1 Load Shaping rates. The purpose of this rate is to reflect the value of buying and selling flat monthly/diurnal blocks of power in the market (with the Load Shaping rate as the proxy market price) to convert a diurnally flat resource within the month into one that, on a planned basis, is flat across the year.

Resource Shaping Billing Determinant. The Resource Shaping billing determinant for each resource is the difference between the planned monthly/diurnal generation from the Exhibit D amounts and the annual average generation from the Exhibit A amounts for the same year.

Resource Shaping Charge. For each resource, the Resource Shaping charge is the product of the Resource Shaping rate and the Resource Shaping billing determinant. 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 for the rate period. On a monthly basis this calculation can result in a charge or a credit.

The flat monthly Resource Shaping charge that results from this calculation will be reflected on the customer's monthly bill. Documentation Table 3.21 shows the Resource Shaping charges that are calculated for the individual resources to which DFS is applied. GRSP II.U.1.(c) includes the formula for calculating the Resource Shaping charges for the individual resources to which DFS is applied.

For Small, Non-Dispatchable Resources (as defined in the CHWM contract), the Resource Shaping charge will not apply. The actual generation amounts will be used in the calculation of the Actual Monthly/Diurnal Tier 1 Load when calculating the PFp Tier 1 Load Shaping charge and Demand charge billing determinants.

3.1.15.2.5 Resource Shaping Charge Adjustment

Resource Shaping Charge Adjustment Rate. The rates used to calculate the Resource Shaping Charge Adjustment are the monthly/diurnal Resource Shaping rates.

Resource Shaping Charge Adjustment Billing Determinant. For each resource, the billing determinant is the difference between the planned monthly/diurnal generation from CHWM contract Exhibit D amounts and the actual monthly/diurnal generation of the resource. 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 Forced Outage

Reserve Service (FORS), TCMS, planned outage replacement, economic dispatch, and Unauthorized Increases in the determination of actual generation. For resources within the BPA balancing authority area, transmission curtailments associated with Dispatcher Standing Orders and reliability protocols related to BPA's balancing services offered through the Ancillary and Control Areas Services rates will be treated as reduced scheduled amounts when calculating the actual generation for such resources.

Resource Shaping Charge Adjustment. For each resource, the Resource Shaping Charge Adjustment is the product of multiplying the Resource Shaping rate by the Resource Shaping Charge Adjustment billing determinant for each monthly/diurnal period. The purpose of this adjustment is to capture the cost or value of the energy differences between the Exhibit D amounts and the actual generation of the resource. This adjustment completes the financial conversion to a flat annual block of power by making up for any energy cost differences between planned and actual generation amounts. On a monthly/diurnal basis this calculation can result in either a charge or a credit. GRSP II.U.1.(d) includes the formula for calculating the Resource Shaping Charge Adjustment for the individual resources to which DFS is applied.

3.1.15.2.6 DFS and Resource Shaping Charge Application to Tier 1 Augmentation

TRM section 8 states that RSS pricing will be used to make certain Federal resource acquisitions financially equivalent to a flat block. TRM, BP-12-A-03, section 3.5 states that Tier 1 Augmentation is assumed to be in the shape of an annual flat block purchase for ratemaking purposes. The costs of Klondike III, a wind resource, are allocated to Tier 1 Augmentation. The RSS module of RAM calculates a DFS capacity charge, DFS energy charge, and Resource Shaping charge for Klondike III. The billing determinant for the DFS energy charge is the planned generation amount based on the historical generation year data, in lieu of actual generation data. In addition, the RSS module calculates a TSS charge for Klondike III. The sum of the charges for Klondike III for each year is allocated to the Tier 1 Composite cost pool under the "Augmentation RSS and RSC Adder" line item. There is no Resource Shaping Charge Adjustment applied to Klondike III. Documentation Table 3.21 shows the summary DFS, Resource Shaping, and TSS charges that are calculated for Klondike III.

3.1.15.3 RSS Secondary Crediting Service (SCS)

SCS provides a credit or charge to a Load Following customer that dedicates to its load its entire share of the output of a hydroelectric Existing Resource. The customer will receive a credit for the energy produced by that resource that is in excess of the monthly/diurnal amounts specified in the CHWM contract Exhibit A. The additional generation would increase BPA's revenues because of the increased secondary energy BPA can market or would lower BPA's costs because of reduced balancing purchases. The customer will receive a charge for any energy shortfall by the resource from the monthly/diurnal Exhibit A amounts, because BPA's secondary revenues would be lower or BPA's balancing costs would be higher. If a customer does not take this service, it must apply the exact Exhibit A amounts to its load, unless the resource is a small, non-dispatchable resource.

The PF-16 rate schedule includes SCS charges. GRSP II.U.2 includes the formulas for calculating the SCS charges or credits for the resources to which SCS is applied. Documentation Table 3.21 includes the individual SCS Administrative charges for the individual non-Federal resources to which SCS is applied.

3.1.15.3.1 SCS Pricing Summary

The charges and credits for SCS are intended to reflect the cost or value of reshaping the customer's resource into its Exhibit A amounts. The SCS charges include the following elements:

- Secondary Energy credit or Shortfall Energy charge, priced at the Resource Shaping rate.
- An Administrative Charge, similar to a reservation fee, based on the forced outage rating of the hydro resource, the PFp Tier 1 Demand rate, and the monthly HLH Exhibit A amounts.

3.1.15.3.2 SCS Shortfall Energy Charges and Secondary Energy Credits

SCS Energy Rate. The rates used to calculate the SCS Shortfall Charge and the Secondary Energy Credit are the monthly/diurnal Resource Shaping rates.

SCS Billing Determinant. For each resource, the billing determinant is the difference between the actual monthly/diurnal generation and the monthly/diurnal generation from Exhibit A amounts. The actual generation amounts will be either the resource meter readings, or resource transmission schedules if the resource requires an e-Tag. For SCS Option 1 only (the power exchange between the customer and BPA), the actual generation amounts shall be net of transmission losses on the BPA transmission system. *See* GRSP III.A.18. The actual generation shall include energy amounts provided through TCMS.

SCS Shortfall Energy Charge/Secondary Energy Credit. For each resource, the charge or credit is the product of multiplying the SCS energy rate by the SCS energy billing determinant for each monthly/diurnal period. 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. GRSP II.U.2.(a) includes the formula for calculating the SCS Shortfall Energy Charges/Secondary Energy Credits for the individual resources to which SCS is applied.

3.1.15.3.3 SCS Administrative Charge

A customer's SCS Administrative charge will be calculated in the form of a capacity reservation fee. This capacity reservation fee's structure mirrors the structure of the FORS capacity charge, described in section 3.5.5.1 below.

SCS Administrative Rate. The rates used to calculate the SCS Administrative charge are the monthly PFp Tier 1 Demand rates.

SCS Administrative Charge Billing Determinant. For each resource, the billing determinant is the monthly HLH Exhibit A amount multiplied by the forced outage rating.

SCS Administrative Charge. For each resource, the SCS Administrative charge is the product of 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 flat monthly SCS Administrative charge that results will be specified in section 2.5.3.2 of Exhibit D of the CHWM contract. Documentation Table 3.21 shows the SCS Administrative charges that are calculated for the individual resources to which SCS is applied. GRSP II.U.2.(b) includes the formula for calculating the SCS Administrative charge for the individual resources to which SCS is applied.

3.1.15.4 Grandfathered Generation Management Service (GMS)

Grandfathered Generation Management Service allows a Load Following customer dedicating the entire output of an Existing Resource that received GMS during Subscription to run that resource to meet its load and offset its Tier 1 load and charges. There is also a GMS Reservation Fee.

GMS Reservation Fee. For each resource, the GMS Reservation Fee is calculated by multiplying the GMS Reservation Fee rate and the GMS Reservation Fee 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.

GMS Reservation Fee 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 U.5.

3.1.15.5 Additional PFp RSS Considerations

3.1.15.5.1 Forced Outage Rating

Each generally recognized type of generating resource has a standard forced outage rating. This rating represents the average percentage of time that a generating resource is unavailable for load service due to unanticipated breakdown. BPA uses a minimum 5 percent forced outage rating for hydroelectric resources, 7 percent for thermal resources, and 10 percent for all other resources. Customers taking services that have charges including the use of a forced outage rating may request that BPA increase the forced outage rating for their resource, and those with a resource other than a hydroelectric resource may request that BPA decrease the forced outage rating to as low as 7 percent.

3.1.15.5.2 Historical Generation Year Resource Amounts Adjusted for Schedules

Typically, the RSS module of RAM will use scheduled amounts for resources that require an e-Tag and meter amounts for "behind-the-meter resources." However, for small resources or small shares of a resource, BPA may apply a meter amount instead of a schedule amount for purposes of pricing RSS if the meter amount produces lower RSS rates and charges. This adjustment applies to RSS provided under the PF rate schedule, discussed above, and the NR and FPS rate schedules, described below.

3.1.15.5.3 Credits to the PFp Tier 1 Customer Cost Pools

Forecast revenue credits will be calculated from the RSS charges. All revenues except those from the DFS Energy Charge, NR Resource Flattening Service, and the Resource Shaping Charge will be credited to the Composite cost pool. The forecast revenues from the DFS Energy Charge, NR Resource Flattening Service energy charge, and Resource Shaping Charge sales are revenue credits to the Non-Slice cost pool. Additional information on these revenue credits is found in sections 3.1.2.1 and 3.1.2.2 above.

3.1.15.5.4 Non-Federal Resource with DFS Remarketing

Section 10 of the CHWM contract states that the customer may elect to remove a new non-Federal resource in the event its Above-RHWM load, as forecast for an upcoming rate period year, is less than the sum of its Tier 2 rate purchase amounts and New Resource amounts. Notice of such election must be provided by October 31 of the year of a rate case initial proposal for Load Following customers. Due to the extended RHWM process for BP-16, this election date was changed to November 30, 2014. Section 10.5 of the CHWM contract states that BPA shall remarket the amounts of removed resources for which the customer purchases DFS in the same manner BPA remarkets Tier 2 rate purchase amounts. The customer will continue to pay for DFS on the entire resource amount that is applied to load and any portion of the resource remarketed by BPA.

DFS Remarketing Rate. The DFS remarketing proceeds are computed for Load Following customers using either the forecast augmentation price or the actual price BPA paid for the power it purchased to meet its remaining Tier 2 load obligation, plus losses, in the applicable fiscal year.

DFS Remarketing Billing Determinant. For each applicable non-Federal resource to which DFS applies, the billing determinant is (i) the customer's total non-Federal resource, less (ii) the amount of the customer's non-Federal resource needed to meet Above-RHWM load, as reflected in the customer's CHWM contract Exhibit A, when updated.

DFS Remarketing Credit. For each resource, the DFS remarketing credit will be the product of multiplying the DFS remarketing rate by the DFS remarketing billing determinant for each applicable year of the rate period. The annual value is divided by 12 to calculate a flat monthly credit. Documentation Table 3.22 shows the forecast monthly DFS Remarketing Credits that are calculated for the individual resources to which the DFS remarketing is applied.

3.2 Priority Firm Exchange Rate Design

3.2.1 The PFx Rate

The PFx rate applies to participants in the Residential Exchange Program (REP) for sales of exchange energy pursuant to a Residential Purchase and Sale Agreement (RPSA) (eligible consumer-owned utilities) or a REP Settlement Implementation Agreement (REPSIA) (eligible investor-owned utilities). Under either an RPSA or REPSIA, the PFx rate is applied to BPA's sales of exchange energy, and the participating utility's ASC is applied to BPA's purchase of exchange energy, where the exchange energy is equal to the utility's eligible residential and farm load. The difference between the amount BPA pays for exchange "purchases" and the amount BPA receives for exchange "sales" determines the amount of monetary REP benefits BPA pays the utility. The PFx rate also applies to any actual power sales to exchanging utilities under contractual "in-lieu" provisions.

The PFx rate has two components: two common Base PFx rates (one for COUs with CHWM contracts and another for all other participants), and utility-specific REP surcharges. The COUs have a different Base PFx rate because the PFp rate is tiered. Neither component of the PFx rate is diurnally differentiated or contains an additional charge for demand. Each participant's ASC is a single mills/kWh rate applied to all kilowatthours. Likewise, the rate design for each participant's PFx rate is a single mills/kWh rate applied to all kilowatthours.

The two Base PFx rates are computed within RAM based on the average PF rate immediately prior to the determination of section 7(b)(2) rate protection. At this point in the ratemaking process, no 7(b)(2) rate protection has been determined, so the Base PFx rates bear no rate protection costs. The PFx rate applicable to IOUs (and any eligible COU without a CHWM contract) is computed by dividing all costs allocated to the PF rate pool by all PF rate pool loads and then adding a transmission charge for delivering the exchange power to the customer. The PFx rate applicable to COUs with CHWM contracts is calculated in the same manner, except that the costs allocated to Tier 2 cost pools are excluded from the numerator and loads served at Tier 2 rates are excluded from the denominator.

Under the 2012 REP Settlement, the utility-specific 7(b)(3) surcharge to recover the cost of providing 7(b)(2) rate protection continues to be assessed, but the surcharge for IOUs also includes the allocation of the costs of Refund Amounts. *See* § 2.2.1.3. The amount of 7(b)(2) rate protection costs allocated to the PFx rates is allocated to each REP participant on a pro rata basis using REP benefits calculated using the Base PFx rates (Unconstrained Benefits) as the allocator. The cost of Refund Amounts is allocated to each IOU using IOU Unconstrained Benefits as the allocator; Refund Amounts are not allocated to COU participants. The total amount allocated to each REP participant is divided by the participant's exchange load to derive its utility-specific 7(b)(3) surcharge.

For each REP participant, the applicable Base PFx rate is added to its utility-specific 7(b)(3) surcharge to determine its utility-specific PFx rate. For each month of the rate period, the participant will submit its exchange load to BPA for the prior month. BPA will multiply this invoiced exchange load by the difference between the participant's ASC and its PFx rate to calculate the amount of REP benefits payable to the participant. *See* Documentation Table 2.4.11.

3.2.2 2012 REP Settlement Agreement Implementation

The 2012 REP Settlement (*see* § 1.5) requires that BPA pay a fixed sum of REP benefits to IOUs eligible for the REP pursuant to a schedule of payments set forth in the 2012 REP Settlement. The yearly fixed sum is included in BPA's revenue requirement and collected in BPA's rates. Each IOU's share of the fixed amount of REP benefits is determined pursuant to the calculations contained in section 6 of the 2012 REP Settlement. In particular, section 6.2 of the 2012 REP Settlement describes a series of adjustments BPA is required to make to certain IOUs' shares of the REP benefits. BPA's implementation of section 6.2, including the specific calculations BPA used to reach the resulting REP allocations, is provided in Documentation Table 2.4.12.

3.3 Industrial Firm Power (IP) Rate Design

3.3.1 IP Energy Rates

The IP rate design includes 24 monthly/diurnal Energy rates, two for each month, one each for HLH and LLH. Monthly and diurnal differentiation of IP Energy rates is performed based on the HLH and LLH differentiation of the PFp Melded rate (*see* § 3.1.14 above).

As described below, IP Energy rates are determined by adjusting the PFp Melded rates by the Value of Reserves (VOR) credit for operating reserves provided by the DSI load, the typical industrial margin, and an REP surcharge. *See* Documentation Table 2.5.8.3.

3.3.1.1 IP Adjustment for Value of Reserves Provided

A VOR credit is included in the IP rate, as provided in section 7(c)(3) of the Northwest Power Act. *See* section 1.2.2 above. The FY 2016–2017 rate period DSI power sales forecast is 91 aMW for each year. *See* Power Loads and Resources Study, BP-16-FS-BPA-03, § 2.4. Based on provisions of DSI contracts currently in place, these power sales are assumed to provide interruption reserve rights (operating reserves) to BPA, and therefore the IP rate includes a VOR credit.

The first step for valuing operating reserves provided by DSIs is to determine a marginal price for these reserves. Because the DSI-supplied reserves are used to meet BPA's reserve obligations, the cost of Operating Reserves – Supplemental is used to establish the marginal value.

The second step in valuing the DSI reserves is to determine the quantity of reserves provided. To calculate this quantity, the total DSI load is reduced to account for wheel-turning load that cannot be curtailed. The wheel-turning load is forecast to be 6 aMW. The interruption reserves provided are 10 percent of the remaining DSI load (85 MW), or 9 MW.

The VOR credit included in the IP-16 rate is 0.973 mills/kWh. *See* Documentation Table 2.4.1 for calculation of the value of DSI reserves.

3.3.1.2 IP Rate Typical Margin

Another component of the IP rate is the typical margin, as provided in section 7(c)(2) of the Northwest Power Act. *See* § 1.2.2. The typical margin is based generally on the overhead costs that COUs add to the cost of power in setting their retail industrial rates. The typical margin included in the IP-16 rate is 0.733 mills/kWh. The methods and calculations used to determine the typical margin are discussed in Appendix A.

3.3.1.3 REP Surcharge

The final component of the IP rate is the REP Surcharge. Section 7(b)(3) of the Northwest Power Act provides that the cost of 7(b)(2) rate protection afforded to preference customers be allocated to all other power sold, which includes power sold at the IP rate. *See* § 1.2.2 above. The cost of rate protection allocated to the IP rate is determined pursuant to the 2012 REP Settlement and is included in the IP-16 rate. The IP-16 REP Surcharge is 8.20 mills/kWh. *See* Documentation Table 2.4.14 for calculation of the REP Surcharge.

3.3.2 IP Demand Rates

The Demand rates for the IP rate schedule are equal to the PFp Demand rates described in section 3.1.6.3 above. As with the PFp Demand charge, the IP Demand billing determinant is applied to only a portion of the DSI peak demand placed on BPA. The IP Demand billing determinant in each billing month is equal to a DSI's highest HLH schedule, or metered amount, minus the average HLH schedule amount, or metered amount, less any applicable Industrial Demand Adjuster. The Industrial Demand Adjuster is a monthly quantity of demand (expressed in kilowatts) that is subtracted from the hourly peak schedule amount when calculating the IP Demand billing determinant. *See* the IP-16 rate schedule, § 2.2.

3.4 New Resources (NR) Rate Design

3.4.1 NR Energy Rates

Monthly and diurnal differentiation of NR energy rates is calculated based on the HLH and LLH differentiation of the PFp Load Shaping rates. *See* Documentation Table 2.5.8.4. The NR energy rates are determined by adjusting each PFp Load Shaping rate by an equal scalar until the

NR energy rates recover the allocated NR revenue requirement minus the forecast NR Demand charge revenue. *See* Documentation Table 2.5.8.4.

After the scaling process is complete, a REP Surcharge is added to each of the monthly/diurnal energy rates. Section 7(b)(3) of the Northwest Power Act provides that the cost of 7(b)(2) rate protection afforded to preference customers be allocated to all other power sold, which includes power sold at the NR rate. *See* § 1.2.2 above. The cost of rate protection allocated to the NR rate is determined pursuant to the 2012 REP Settlement. The NR-16 REP surcharge is 8.20 mills/kWh. *See* Documentation Table 2.4.14 for calculation of the REP Surcharge.

3.4.2 NR Demand Rates

The Demand rates for the NR rate schedule are equal to the PFp Demand rates described in section 3.1.6.3 above. As with the PFp Demand charge, the NR Demand billing determinant is only a portion of the peak demand placed on BPA. The NR Demand billing determinant will be equal to the highest NR Hourly Load during HLH less the average hourly HLH energy purchased in that particular month at the NR energy rates.

3.4.3 NR Energy Shaping Service for New Large Single Loads

The NR Energy Shaping Service (ESS) is offered to Load Following customers serving a New Large Single Load (NLSL) with non-Federal resources. ESS includes a capacity component and an energy component. The capacity component applies to the amount of capacity that a customer requests BPA to stand ready to provide to the customer's NLSL(s). The energy component credits or debits the customer for energy differences between the energy amounts provided by the customer to serve its NLSL(s) and the customer's measured NLSL(s). *See* the NR-16 rate schedule and GRSP II.G.1.

3.4.3.1 NR ESS 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. A customer purchasing NR ESS must have established monthly capacity amounts for the FY 2016–2017 rate period prior to February 1, 2015. However, at least 30 days prior to any month, the customer may notify BPA of a change in the amount of capacity it is requesting BPA to stand ready to serve its NLSL(s) for that month.

The billing determinant is multiplied by the applicable monthly NR demand rate. *See* the NR-16 rate schedule, section 2.2.1, to calculate the monthly NR ESS Capacity charge.

A monthly capacity check will be performed to verify that the customer's actual capacity use did not exceed the monthly amount of capacity it asked 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 section 3.4.3.2 below, in that same month, or (ii) zero. The Unauthorized Increase (UAI) Charge for demand will apply to actual capacity amounts used in excess of the monthly amounts of capacity included in the customer's request to BPA.

3.4.3.2 NR ESS Energy Charge

The energy component of the NR Energy Shaping Service charge 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 its NLSLs.

The NR ESS Energy charge can be either a positive or negative amount and is determined through a two-step process. The first step determines the applicable rate treatment: Rate Treatment A or B. The second step applies the rate treatment as determined in the first step.

Step 1

Step 1 determines whether on a net monthly basis the customer purchased energy from BPA or provided energy to BPA. Step 1 subtracts the energy amounts provided by the customer to serve its NLSLs in a billing month from the measured load of the customer's NLSLs in the same billing month. If the result of this calculation is greater than zero, Rate Treatment A applies. If the result is zero or negative, Rate Treatment B applies.

Step 2

Rate Treatment A. Rate Treatment A first calculates two energy billing determinants each month, one for the HLH and one for the LLH. Each of the two billing determinants is equal to the (1) measured energy load of the customer's NLSLs 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 any period can be negative. The billing determinants are multiplied by the applicable monthly/diurnal NR energy rates from section 2.1.1 of the NR rate schedule to yield that billing month's energy charge or credit.

Rate Treatment B. Rate Treatment B calculates daily diurnal billing determinants for the billing month, resulting in two billing determinants for each day with HLH and LLH periods and one billing determinant for days with only a LLH period. The energy billing determinant is equal to (1) the measured energy load of the customer's NLSLs receiving this service during the 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 Price Index (or its replacement) for the same daily/diurnal period to calculate the daily/diurnal energy charge. If any of the Mid-C prices specified above is less than zero, the applicable rate will be zero. The monthly sum of such amounts may be adjusted in accordance with three defined thresholds. *See* GRSP II.G.1.

3.4.4 NR Resource Flattening Service

The NR Resource Flattening Service (NRFS) is applicable to Load Following customers that apply the generation output of a non-dispatchable Specified Resource to a New Large Single Load. *See* the NR-16 rate schedule and GRSP II.G.2.

3.4.4.1 NRFS Energy Rate

A unique energy rate is developed for each resource to which NRFS is applied. The purpose of this rate is to reflect the potential cost of storing and releasing energy to offset the hourly variability of the resource's generation. The RSS module of RAM calculates the NRFS energy rate for each resource. 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.

3.4.4.2 NRFS 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. For resources within the BPA balancing authority area, transmission curtailments associated with Dispatcher Standing Order(s) and reliability protocols related to BPA's balancing services offered through the Ancillary and Control Areas Services rates will be treated as reduced scheduled amounts when calculating the actual generation for such resources.

3.4.4.3 NRFS Energy Charge

The NRFS energy charge is the product of multiplying the NRFS energy rate by the NRFS energy billing determinant for each month. No customers are forecast to take the NRFS during the BP-16 rate period. GRSP II.G.2 includes the formula for calculating the NRFS Energy charges for the individual resources if the NRFS is required.

3.5 Firm Power and Surplus Products and Services Rate Design, Resource Support Services, and Transmission Scheduling Service

Products and services available under the FPS rate schedule are described in the FPS-16 rate schedule. 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. Products priced under the FPS-16 rate schedule may be sold at market-based or negotiated rates, which may have a demand component, an energy component, or both.

The FPS-16 rate schedule provides for eight categories of products and services: (1) Firm Power (capacity and/or energy); (2) Capacity Without Energy; (3) Shaping Services; (4) Reservations and Rights to Change Services; (5) Reassignment or Remarketing of Surplus Transmission Capacity; (6) Services for Non-Federal Resources; (7) Unanticipated Load Service; and (8) Other Capacity, Energy, and Power Scheduling Products and Services.

3.5.1 Firm Power and Capacity Without Energy

When available, BPA sells firm power (capacity and/or energy), including secondary energy or firm capacity, for use within and outside the Pacific Northwest. Such power sales are made under the FPS rate schedule at rates and billing determinants specified by BPA or as mutually agreed by BPA and the customer. Sales of firm power may be subject to an REP surcharge. The applicability of an REP surcharge will be determined by BPA at the time of the sale, as set forth in the 2012 REP Settlement Agreement.

3.5.2 Shaping Services

BPA sells shaping services, when available, for use within and outside the Pacific Northwest. Such services are sold under the FPS rate schedule at rates and billing determinants specified by BPA or as mutually agreed by BPA and the customer.

3.5.3 Reservations and Rights to Change Services

BPA offers reservations of power and services, when available, and the rights to change sales and services for use within and outside the Pacific Northwest. Such services are sold under the FPS rate schedule at rates and billing determinants specified by BPA or as mutually agreed by BPA and the customer.

3.5.4 Reassignment or Remarketing of Surplus Transmission Capacity

Power Services reassigns or remarkets its surplus transmission capacity, when available, that has been purchased from a transmission provider, including BPA Transmission Services, consistent with the terms of the transmission provider's Open Access Transmission Tariff. Power Services sells this surplus transmission capacity to parties within and outside the Pacific Northwest. Such services are sold under the FPS rate schedule at rates and billing determinants specified by BPA or as mutually agreed by BPA and the customer.

3.5.5 Services for Non-Federal Resources

BPA is offering Forced Outage Reserve Service and Transmission Scheduling Service at posted FPS rates. FORS is a Resource Support Service and is offered under the FPS rate schedule to customers with resources that meet specific requirements specified in the CHWM contract. For customers without CHWM contracts, FORS would be offered, if available, under the Reservations and Rights to Change Services part of the FPS rate schedule. Further information is provided in section 3.5.5.1 below.

TSS is not a Resource Support Service but is related to the services that comprise RSS and is being offered under the FPS rate schedule. It is a required service for customers with resources that meet eligibility requirements specified in the CHWM contract. Further details on TSS and TCMS are provided in section 3.5.5.2 below.

TCMS is also not a Resource Support Service but is related to TSS and is being offered under the FPS rate schedule. It is a service for customers with resources that meet eligibility requirements specified in the CHWM contract.

BPA also includes pricing for Resource Remarketing Service in the FPS rate schedule. RRS is a service that BPA may make available, at its discretion, to Load Following customers where BPA remarkets non-Federal resources on behalf of customers and provides them with a remarketing credit net of possible remarketing fees for doing so. Further details on RRS are provided in section 3.5.5.3 below.

The FPS rate schedule includes a section on the general rate application of the FORS-related, TSS-related, and RRS-related charges and credits. GRSP II.U includes the formulas for calculating the FORS Capacity and Energy Charges, TSS and TCMS Charges, and RRS Credit for the resources to which FORS, TSS/TMCS, or RRS is applied.

3.5.5.1 Forced Outage Reserve Service

FORS is an optional service for BPA to provide an agreed-upon amount of capacity and energy to a customer with a qualifying resource that experiences a forced outage. This service can be considered an insurance product in the event of an unforeseen outage at a generating resource. If a Load Following customer does not choose to take this service, it must supply replacement power if its resource experiences a forced outage. Unless stated otherwise, the resource amounts used in these calculations are those specified in the customer's CHWM contract Exhibit D (Exhibit D amounts), and are planned generation amounts based on hourly generation from the most recent historical year.

3.5.5.1.1 FORS Pricing Summary

The charges for FORS are intended to reflect the cost of BPA (1) reserving capacity to back up a resource as insurance to cover a potential forced outage, and (2) providing replacement energy should a forced outage occur.

The FORS Charges include the following elements:

- A FORS Capacity charge based on the PFp Tier 1 Demand rate, the calculated firm capacity of the resource for customers whose resource is also taking DFS, and the forced outage rating for the applicable resource.
- A FORS Energy charge based on a Mid-C index price under two conditions and the kilowatthours supplied during a forced outage event.

3.5.5.1.2 FORS Capacity Charge

FORS Capacity Rates. The rates used to calculate the FORS Capacity charge are based on the PFp Demand rates and are listed in GRSP II.U.3.(a)(1).

FORS Capacity Billing Determinant. For each resource, the Capacity billing determinant is the monthly firm capacity multiplied by the forced outage rating. The firm capacity is calculated by the RSS module of RAM in the manner described for the DFS Capacity billing determinant. *See* § 3.1.15.2.2. The forced outage rating for a resource taking FORS has the same considerations as described in section 3.1.15.5.1 above.

FORS Capacity Charge. For each resource, the FORS Capacity charge is the product of multiplying the FORS Capacity rate by the FORS Capacity billing determinant for each month. The sum of the monthly values is divided by 12 to calculate a flat monthly charge. The FORS Capacity charge is specified in section 2.4.5.3 of Exhibit D of the CHWM contract. Documentation Table 3.21 shows the FORS Capacity charges that are calculated for each resource currently requesting FORS. The formula for calculating the FORS Capacity charge for each individual resource to which FORS is applied is shown in GRSP II.U.3.(a)(3).

3.5.5.1.3 FORS Energy Charge

The purpose of the Energy charge is to pass through the cost of replacement energy that BPA provides during a customer's forced outage.

FORS Energy Rate. The rate for the energy provided during the first 24 hours of a forced outage will be the average of the hourly Powerdex Mid-C Price or its replacement during the 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 for the applicable diurnal period the energy is provided. If any of the Mid-C prices specified above is less than zero, the FORS Energy rate calculation will be zero for such negative value.

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

FORS Energy Charge. For each resource, the FORS Energy charge is the product of multiplying the FORS Energy rate by the FORS Energy billing determinant. GRSP II.U.3(b) shows the formula for calculating the FORS energy charges for the individual resources to which FORS is applied.

3.5.5.2 Transmission Scheduling Service and Transmission Curtailment Management Service

TSS is a service provided by Power Services to undertake certain scheduling obligations on behalf of the customer. TCMS is a feature of TSS under which BPA provides either replacement transmission or replacement energy to customers that have qualifying resources that experience transmission events pursuant to the conditions specified in Exhibit F of the CHWM contract.

If a Load Following customer is served by transfer or is purchasing DFS or SCS services from BPA, it is required to have the TSS provisions added to its CHWM contract. Many customers meeting these criteria do not have a non-Federal resource with an e-Tag that must be scheduled to their load. Only customers that have a non-Federal resource that requires an e-Tag will be charged for TSS services. Pursuant to the Load Following CHWM contract, for a customer that is not required to take TSS given the criteria described above, TSS is an optional service if the customer wishes to have BPA produce the e-Tags for its resource(s). If a Load Following customer with a non-Federal resource is not required by its contract to take this service or elects not to take this service, it is required to supply replacement transmission or power when the resource's transmission path experiences an outage or curtailment. If it is unable to do so, it may face an Unauthorized Increase (UAI) charge.

3.5.5.2.1 TSS/TCMS Pricing Summary

The charge for TSS reflects the cost of scheduling a resource to its Point of Delivery (POD). The charge for TCMS reflects the cost of providing either replacement transmission or replacement energy when a transmission event occurs. A unique set of charges will be calculated for each resource to which TSS and TCMS are applied. The TSS and TCMS services are applicable to only certain resources a customer may have, as described in Exhibit F of the Load Following CHWM contract. Certain customers must have the TSS provisions included in their CHWM contracts even though they do not have non-Federal resources scheduled to load. These customers will not have a separate TSS charge on their bill. TSS may apply to a resource and TCMS may not, but TCMS will never apply to a resource to which TSS does not apply.

The TSS/TCMS charges include the following elements:

- A monthly TSS charge based on the dedicated resource megawatthour amounts found in Exhibit A of the Load Following CHWM contract for FY 2016 and FY 2017 for Specified Resources and Unspecified Resource Amounts for resources requiring an e-Tag. Although the contract states these values in megawatthours, BPA bills on kilowatthours, so the appropriate conversion is made.
- A TSS rate that is based on the Operations Scheduling costs for the two years of the rate period divided by the total megawatthours BPA has scheduled in the two most recent historical years.

- An Annual Open Access Technology International, Inc. (OATI) registration fee.
- An after-the-fact TCMS charge based on replacement power or transmission costs caused by a transmission event.

3.5.5.2.2 TSS Charge

TSS Rate. The RSS module of RAM calculates a TSS rate that is applied to the billing determinant described below. The rate is calculated by dividing the forecast operations scheduling cost for the rate period (including costs associated with power scheduling preschedule, real-time, and after-the-fact functions) by the total megawatthours of power BPA scheduled in FY 2013 and FY 2014. *See* Documentation Table 3.8.

TSS Billing Determinant. The TSS billing determinant is the total kilowatthours of planned generation the customer has dedicated to load during the rate period, as specified in Exhibit A of the CHWM contract.

TSS Charge. For each resource, the TSS Charge is the product of multiplying the TSS rate by the TSS billing determinant for each month of the rate period (or an individual fiscal year if this service applies in only one fiscal year). The sum of the monthly values is divided by 24 (or 12 if the service applies in only one fiscal year) to calculate a flat monthly charge.

The TSS Charge is subject to a cap (not including adjustments made to recover the cost of the OATI registration fee described below) for Specified Resources. If the annual cost for the Specified Resource using the TSS rate exceeds $978/month, then the monthly charge is capped at $978/month. The cap is schedule transaction-based. It is the result of multiplying 30 (the average number of schedules in a month, *i.e.*, one per day) by the forecast operations scheduling cost for the rate period, divided by the total number of schedules Power Services produced in

FY 2013 and FY 2014. If the annual cost for the Unspecified Resource Amount using the TSS rate exceeds $2,934/month, then the monthly charge is capped at $2,934/month. This cap is also transaction-based and follows the same methodology applied to Specified Resources but assumes three daily transactions. It is the result of multiplying 90 (the average number of schedules in a month, *i.e.*, three per day) by the forecast operations scheduling cost for the rate period, divided by the total number of schedules Power Services produced in FY 2013 and FY 2014.

BPA will include in a customer's TSS charge(s) the forecast cost that BPA incurs on behalf of the customer for the annual OATI registration fee.

Documentation Table 3.21 shows the individual TSS charges that are calculated for the individual resources to which only TSS is applied, and individual resources to which TSS is applied in addition to other RSS products. GRSP II.U.4(a)(3) shows the formula for calculating the TSS charge for the individual resources to which TSS is applied.

3.5.5.2.3 TCMS Charge

A TCMS rate (GRSP II.U.4) is applied to recover replacement power or transmission costs based on actual transmission events that occur on the planned delivery path between a customer's resource and its load. These transmission events and resource eligibility requirements are defined by terms specified in Exhibit F of the customer's CHWM contract.

TCMS Charge if Replacement Power is Provided. The TCMS rate will be the Powerdex Mid-C hourly index price or its replacement for each hour the transmission event occurs. If a Mid-C price is less than zero, the TCMS energy rate for that hour will be zero. The TCMS billing determinant is the total actual kilowatthours in each hour of replacement power BPA supplies. For each eligible resource, the TCMS charge is the product of multiplying the TCMS rate by the TCMS billing determinant for each hour of the month.

TCMS Charge if Alternative Transmission is Provided. If Point-to-Point transmission is used for the alternate transmission path used to deliver the customer's eligible resource, for each resource the TCMS charge is the cost of the additional Point-to-Point transmission purchases plus any additional costs, including real power losses, associated with using the replacement transmission.

GRSP II.U.4(b)(3) shows the formula for calculating the TCMS charges for the individual resources to which TCMS is applied.

For the BP-16 rate period, the TCMS charge does not include a non-firm Network or Point-to-Point reservation fee. BPA is reserving the right to include such a fee in future rate periods for customers wheeling their non-Federal resource to their loads on non-firm Network or non-firm Point-to-Point transmission.

Application of TCMS to the Tier 2 rates is described in section 3.1.9.1 above.

3.5.5.3 Resource Remarketing Service

Exhibit D of the CHWM contract for Load Following customers offers an optional service for customers that have purchased non-Federal resources in anticipation of future need. At the customer's request and with BPA's agreement, BPA will remarket the excess non-Federal resource amounts on the customer's behalf until the customer's need meets or exceeds the non-Federal resource amount. In order to qualify for this service the customer must also request DFS for the non-Federal resource. The DFS charges will be applicable to both the non-Federal resource amounts the customer dedicates to its load and any portion that BPA remarkets on the customer's behalf. Documentation Table 3.22 shows the individual RRS credits that are calculated for the individual resources to which RRS is applied.

3.5.5.3.1 RRS Credit

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

RRS Billing Determinant. The RRS billing determinant will be the annual average megawatt Resource Remarketed Amounts in the customer's CHWM contract Exhibit D (when updated).

RRS Credit. For each resource, the RRS Credit will be the product of multiplying the RRS rate by 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.

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

3.5.5.4 TSS Charge Application to Tier 1 Augmentation

TRM section 8 states that RSS pricing will be used to make Federal resource acquisitions financially equivalent to a flat block. In addition, Tier 1 Augmentation is assumed for ratemaking purposes to be in the shape of an annual flat block purchase. *See* TRM, BP-12-A-03, § 3.5. The one resource whose costs are allocated to Tier 1 Augmentation is Klondike III, a scheduled resource that requires an e-Tag. The RAM RSS module calculates a TSS charge for this resource. The TSS charge is added to the RSS charges for each year of the rate period that are allocated to the Composite cost pool under the "Non-Slice Augmentation RSC Revenue Debit/(Credit)" line item.

3.5.6 Unanticipated Load Service (ULS)

Under the FPS-16 rate schedule, the Resource Replacement (RR) rate will be applied to Unanticipated Load Service for circumstances that cause an increase in a customer's load placed on BPA and not anticipated in the rate case. Such circumstances could include, but are not limited to, delays in the online date of a customer's specified resource for Above-RHWM service; New Specified Resources that are 10 aMW or less and either experience permanent failure during the rate period or fail to come online; and Transfer customers that both (1) cannot secure Firm Network Transmission (NT) from source to sink for their Dedicated Non-Federal resource to their Above-RHWM load by the time power deliveries are to begin under the Regional Dialogue contract, and (2) are expected to face high TCMS charges due to their reliance on Secondary Network Transmission while they pursue Firm Network Transmission. The provision of ULS will be at BPA's sole discretion.

The energy rate for the RR rate is equal to the Load Shaping rate or the projected market price calculated when a request for ULS is made, whichever is greater. *See* section 3.1.6.2 above for a description of the Load Shaping rate. The ULS Demand rate is equal to the PFp Demand rate, described in section 3.1.6.3 above. The ULS under the FPS-16 rate schedule is specified in GRSP II.Z.4.

3.5.7 Other Capacity, Energy, Ancillary, and Scheduling Products and Services

BPA may sell, for use within and outside the Pacific Northwest, other 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, when available, under the FPS rate schedule. Such products and services may include, but are not limited to: (1) interruptible energy; (2) resource support and scheduling services for non-Federal resources not eligible for services under section 6 of the 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). Billing determinant(s) and rate(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.

3.6 General Transfer Agreement Service Rate Design

About half of BPA's power customers are served by the transmission systems of third parties, which are entities other than BPA. Under the CHWM contract, BPA must acquire transmission services from these third-party transmission providers to deliver Federal power to BPA's power customers. This third-party transmission service is commonly referred to as transfer service.

Transfer service customers may be subject to one or more separate charges from BPA: (1) the General Transfer Agreement (GTA) Delivery Charge; (2) the Transfer Service Operating Reserve Charge; and (3) the WECC and Peak Charges. These charges are in Power GRSP II.J, General Transfer Agreement Service Charges. In addition to these charges, transfer service customers are responsible for the cost of any distribution upgrades associated with their respective points of delivery, as provided in the Supplemental Direct Assignment Guidelines, Power GRSP I.E.

3.6.1 GTA Delivery Charge

The GTA Delivery Charge, Power GRSP II.J.1, is a charge for low-voltage delivery service of Federal power provided under GTAs and other non-Federal transmission service agreements over a third-party transmission system. The GTA Delivery Charge applies to power customers that take delivery at voltages below 34.5 kV unless such costs have been directly assigned to the specific customer. The GTA Delivery Charge is a dollars per kilowatthour rate levied on customer load at its low-voltage points of delivery (POD) at that customer's system peak. Calculation of the rate is described below; like other rates, the GTA Delivery rate is the result of dividing a numerator by a denominator.

3.6.1.1 Numerator: GTA Delivery Rate Revenue Requirement

The revenue requirement for the GTA Delivery rate is computed by compiling the total low-voltage distribution, use of facility, and delivery charges paid by Power Services to third-party transmission providers in each of FY 2013 and FY 2014. Any known changes for the FY 2016–2017 rate period were added and the average for the two years was calculated.

NorthWestern Energy (NorthWestern) is BPA's only third-party transmission provider that does not charge separately for low-voltage delivery. To estimate a cost for low-voltage delivery services provided by NorthWestern, the average cost of all other transmission providers' low-voltage charges was applied to the transfer service customer loads served by low-voltage facilities on NorthWestern's system.

The conversion of the Southeast Idaho transfer loads to service under a non-federal Open Access Transmission Tariff (OATT) will begin in July 2016, which will increase low-voltage charges by an estimated $50,000 average annually. This addition was incorporated in the last three months of FY 2016 and all of FY 2017. The total average cost for FY 2013 and FY 2014, as adjusted, is $2,109,973. This cost is the numerator in the GTA Delivery Charge calculation.

3.6.1.2 Denominator: GTA Delivery Forecast Load

The average of FY 2013 and FY 2014 customer system peaks was determined by reviewing customer bills and extracting customer load data for the low-voltage PODs at the time of each customer's system peak. Points of delivery removed during FY 2013 and FY 2014 were not included in the calculations, and permanent customer load shifts were assumed in determining loads as well. The average of the FY 2013 and FY 2014 customer system peaks is 2,235,919 kW. This average peak value is the denominator in the GTA Delivery rate calculation.

3.6.1.3 GTA Delivery Rate Calculation

The FY 2013–2014 average revenue requirement is divided by the FY 2013–2014 average customer system peak to calculate the GTA Delivery rate, as shown below:

Distribution, Use-of-Facility, and Low-Voltage Costs:	$2,109,973
BPA Customer System Peak:	2,235,919 kW
GTA Delivery Rate FY 2016–2017:	$0.94 per kW/Mo

3.6.2 Transfer Service Operating Reserve Charge

The Transfer Service Operating Reserve Charge is designed to compensate BPA for the cost of acquiring operating reserves assessed by third-party transmission providers and non-BPA balancing authorities for service to transfer service customers' loads. Regional reliability standard BAL-002-WECC-2, which became effective on October 1, 2014, requires transmission customers to acquire three percent of the required operating reserves from the source balancing authority (*i.e.,* where the generation that serves their load is located) and three percent of the required operating reserves from the sink balancing authority (*i.e.,* where their load is located). If the source and sink balancing authorities are the same, the transmission customer pays its host balancing authority a total of six percent of the required operating reserves. If the transmission customer's resources and loads are located in different balancing authorities, the transmission customer pays three percent of the required operating reserves to the source balancing authority and three percent of the required operating reserves to the sink balancing authority.

Prior to BAL-002-WECC-2, transfer service customers, like all other directly connected power customers, paid BPA Transmission Services six percent for the required operating reserves for deliveries of Federal power. However, with BAL-002-WECC-2, transfer service customers pay only three percent for operating reserves to Transmission Services (the source balancing authority) for Federal power deliveries. Power Services holds the transmission contract on the third-party system, and therefore, Power Services must pay the three percent of operating reserve required for loads in the sink balancing authority. Consequently, BPA will accrue additional ancillary services costs as Power Services is required to acquire operating reserves for delivery of Federal power to transfer service customers' loads located outside BPA's balancing authority area. The Transfer Service Operating Reserve Charge for the FY 2016–2017 rate period is designed to mitigate the cost shift described above.

Assessment of the Transfer Service Operating Reserve Charge is conditioned on the satisfaction of two criteria:

(1) BPA serves the power customer by transfer service; and
(2) the transfer service customer is not already paying BPA for operating reserves based on the regional reliability standard BAL-002-WECC-2 for the customer's load (*i.e.*, under the ACS-16 rate schedule).

The Transfer Service Operating Reserve rates are the same as the ACS-16 rates for operating reserves that BPA charges customers that have load in the BPA balancing authority area. That is, the Transfer Service Spinning Operating Reserve rate is equal to the ACS-16 Operating Reserve – Spinning Reserve Service rate, and the Transfer Service Supplemental Operating Reserve Charge is equal to the ACS-16 Operating Reserve – Supplemental Reserve Service rate. The monthly billing determinant for both Transfer Service Operating Reserves charges is the metered load of the customer served by transfer (non-BPA balancing authority area load).

The forecast revenue associated with the Transfer Service Operating Reserve Charge – Spinning Reserve Service is $1.5 million for FY 2016 and $1.5 million for FY 2017. The forecast revenue associated with the Transfer Service Operating Reserve Charge – Supplemental Reserve Service is $1.4 million for FY 2016 and $1.4 million for FY 2017. It is anticipated that the increased revenue from Transfer Service customers will be offset by the increased ancillary service costs Power Services will pay to third-party transmission providers.

3.6.3 Transfer Services WECC and Peak Charges

BPA has designed new transfer service WECC and Peak charges for FY 2016–2017. (The Western Electricity Coordinating Council (WECC) was split into a Regional Entity (WECC) and a Regional Coordinator (Peak Reliability or Peak).) These charges will recover costs assessed to BPA by WECC and Peak relating to BPA transfer service customers' loads located outside BPA's balancing authority area. The Transfer Services WECC and Peak Charges apply to all transfer service customer loads located outside of the BPA balancing authority area. The Transfer Service WECC and Peak charges are separate stand-alone charges.

Background on WECC and Peak Charges. WECC and Peak each assess charges to loads located in balancing authority areas within the western interconnection to support their regional operations; WECC and Peak develop these charges. The charges are based on a Net Energy for Load (NEL) value, which includes all loads within a balancing authority area, including system losses. Each balancing authority submits its NEL to WECC and Peak yearly. WECC and Peak add the NEL amounts for all balancing authority areas to identify a total NEL for all loads in the western interconnection. The total NEL is then divided into the annual revenue requirement for WECC and the annual revenue requirement for Peak to establish two $/MWh assessments. For example, for CY 2015, WECC's rate is $0.0424/MWh and Peak's rate is $0.056/MWh.

WECC and Peak Assessments. The WECC and Peak rates are assessed to the individual loads identified in the NEL data submitted by the balancing authority areas. The NEL submissions to WECC and Peak, however, vary across the region. Some balancing authority areas identify and submit individual customer loads in the NEL. In these balancing authority areas, customers receive an individual assessment for the WECC and Peak charges. Other balancing authority areas, however, identify and submit a single load for the balancing authority areas, with no differentiation between native and non-native loads. In these instances, the balancing authority area receives a single assessment from WECC and Peak for all loads in the balancing authority area. BPA's transfer service customer loads are located in balancing authority areas that report in both manners.

BPA's Transfer Services WECC and Peak Charges. FY 2016–2017, WECC and Peak will bill BPA Power Services for all NEL values reported by the balancing authority areas that are associated with transfer service customer loads outside of the BPA balancing authority area. BPA will recover this assessment from all transfer service customer loads located outside of the BPA balancing authority area, through the Transfer Services WECC Charge and Peak Charge described below, regardless of how the reporting balancing authority area treats the transfer service customer's load in its NEL submission.

3.6.3.1 Transfer Service WECC Rate

3.6.3.1.1 Transfer Service WECC Revenue Requirement

To forecast the BPA revenue requirement for the BPA Transfer Services WECC rate, total NEL reported to WECC is computed for BPA transfer service customer loads outside BPA's balancing authority area. The 2015 WECC NEL assessment list was used to identify specific transfer service customers by name, their corresponding NEL amounts, and NEL amounts associated with only BPA by the reporting balancing authority areas. All of these NEL amounts are then summed to establish a total transfer service NEL value. The NEL quantities include losses, as do the NEL quantities WECC and Peak use to assess their charges. The 2015 WECC NEL assessment is based on 2013 load information, which is the most current information available for forecasting BPA's WECC assessment for transfer service customers for FY 2016–2017.

The revenue requirement for the Transfer Services WECC Rate is computed by multiplying the total transfer service customer NEL value by the WECC rate (as computed by WECC at $0.0424/MWh), as shown in Documentation Table 3.23. This rate was adjusted by applying inflation rates of 1.68 percent for FY 2016 and 1.60 percent for FY 2017, with the final revenue requirement equaling the average of the inflated FY 2016 and FY 2017 amounts, also shown in Documentation Table 3.23.

3.6.3.1.2 Transfer Service WECC Rate Calculation

The Transfer Service WECC rate is computed using the WECC revenue requirement as the numerator. The divisor is the total of all BPA transfer service customers' load from outside the BPA balancing authority area. Unlike the calculation for the revenue requirement, transfer service customer loads that are in balancing authority areas that do not report a separate NEL for BPA transfer service loads are included in the divisor. Each balancing authority area's NEL value has system losses removed to align with the monthly billing determinant, which does not include losses. The FY 2016–2017 average revenue requirement is divided by the forecast total NEL to calculate the rate, as shown in Documentation Table 3.23.

3.6.3.2 Transfer Service Peak Rate

3.6.3.2.1 Transfer Service Peak Rate Revenue Requirement

As with WECC, Peak uses the NEL values reported by the individual balancing authority areas to determine charges for individual transfer service customers. The Transfer Service Peak revenue requirement is then computed using the Total Transfer Service Customer NEL value (*see* Documentation Table 3.23), multiplied by the Peak rate (as computed by Peak at $0.056/MWh). This rate is adjusted by applying inflation rates of 1.68 percent for FY 2016 and 1.60 percent for FY 2017 to the revenue requirement amount as shown below, with the final revenue requirement equaling the average of the inflated FY 2016 and FY 2017 amounts, also shown in Documentation Table 3.23.

3.6.3.2.2 Transfer Services Peak Rate Calculation

As with the Transfer Services WECC Rate, the Transfer Services Peak Rate is computed using a numerator consisting of the Transfer Services Peak Rate revenue requirement. The divisor is the total of all BPA transfer service customers' load from outside the BPA balancing authority area. The FY 2016–2017 average revenue requirement is divided by the forecast total NEL to calculate the rate, as shown in Documentation Table 3.23.

3.6.3.3 Transfer Service WECC and Peak Charge Billing Determinants

The billing determinant for the transfer services WECC and Peak charges is the total monthly kilowatthours of non-BPA balancing authority area transfer load as shown on each transfer service customer's monthly BPA power bill. The MWh units used in this rate study are converted to kWh units for the purpose of establishing the rate.

3.6.4 Southeast Idaho Load Service Five-Year Market Purchases

BPA has been obtaining transfer service for preference customers in Southeast Idaho since the 1960s. Since 1989, BPA has used an exchange agreement with PacifiCorp and a transmission wheeling agreement to deliver power to these customers. The exchange agreement with PacifiCorp will expire in June 2016. Because of limited transmission capability between BPA's system and BPA's Southeast Idaho customers, BPA has entered into two five-year fixed-price market purchases starting in July 2016 as part of an interim plan of service. These purchases will be used to serve a portion of BPA's transfer customer load located in Southeast Idaho beginning in July 2016.

The cost of these purchases, $53.7 million for FY 2016-2017, is allocated in two parts. The fixed price of the market purchases, less a market "delta" (difference), is allocated to balancing purchases which is assigned to the Non-Slice cost pool. This cost is $47.1 million for the 2-year rate period. The remaining cost of the purchases, the market delta, is allocated to the transfer service budget, which is a component of the Composite cost pool. This cost is $6.6 million for the 2-year rate period. *See* Documentation Table 3.25, line 13, columns B and C.

The market delta reflects the difference in price due to BPA's market purchases being sourced from resources outside the Mid-Columbia market footprint. The market delta is determined by calculating the difference between the market purchase contract prices and the Intercontinental Exchange (ICE) forward Mid-Columbia power price. To calculate the delta, the ICE forward market price for the entire contract term is assumed to be the one in effect at the time each contract was finalized. The first market purchase was finalized on May 9, 2014, and the second on September 30, 2014.

For the FY 2016–2017 rate period and beyond, this new cost to the transfer service budget (the delta) is forecast to be fixed at $6.01/MWh for both of the two forward market purchases.

Documentation Table 3.24 shows the calculation of the total transfer service cost of $219,386,064 for the two five-year Southeast Idaho market purchases and the total 5-year delta cost of $27,131,407. Documentation Table 3.25 shows the calculation of the monthly and annual delta costs for the duration of the two market purchases.

Values for calculating the deltas for the last six months of the contract, January 2021 through June 2021, needed to be synthesized in order to complete the calculations due to limitations in the monthly light load ICE market data. This was done by taking the previous year's (January 2020 thru June 2020) monthly light to heavy ratio percentage and multiplying the following year's monthly heavy load prices by the resulting percentages calculated in 2020.

4. REVENUE FORECAST

The revenue forecast calculates the expected revenue from power rates and other sources for the rate period, FY 2016–2017, and the current year, FY 2015. Two revenue forecasts are prepared. The first uses rates from the rate schedules currently in effect (BP-14 rates), and the second uses proposed rates (BP-16 rates). The revenue forecasts are used to test whether current rates and proposed rates will recover the power revenue requirement. If the revenue test shows that revenues at current rates will not generate sufficient revenue to recover the power revenue requirement, new rates are calculated and revenues at proposed rates are generated. *See* Power Revenue Requirement Study, BP-16-FS-BPA-02, §§ 3.2 & 3.3. Both forecasts are based on the Power Loads and Resources Study (BP-16-FS-BPA-03) forecast of firm loads for the current fiscal year and the rate period. Because the same load forecast is used for both revenue forecasts, the only revenues that change between current and proposed rates are Priority Firm Power (PF) and Industrial Firm Power (IP) revenues. All other revenues remain constant between the two forecasts.

In addition to forecasts of revenues, this chapter of the study presents power purchase expenses that are directly related to balancing purchases needed to meet load under different water conditions. Power purchases are included in the forecast for FY 2015–2017 and discussed in section 4.5 below.

The revenue forecast includes revenue calculations for the current year, FY 2015, to estimate the amount of financial reserves available to BPA at the beginning of the rate period. *See* Power Revenue Requirement Study, BP-16-FS-BPA-02, § 1.1.

The revenue forecast is divided into four main categories: (1) revenues from gross sales, described in section 4.1 below; (2) miscellaneous revenues, described in section 4.2; (3) revenues from generation inputs for ancillary, control area, and other services, described in section 4.3; and (4) Treasury credits, described in section 4.4.

4.1 Revenue Forecast for Gross Sales

Gross Sales is the largest category of revenue for Power Services. There are nine sources of revenue in this category:

1. Priority Firm power sales under the CHWM contracts, described in section 4.1.1
2. New Resource Firm Power, described in section 4.1.2
3. Industrial Firm Power sales to DSIs, described in section 4.1.3
4. pre-Subscription contract sales, described in section 4.1.4
5. short-term market sales, described in section 4.1.5
6. long-term contractual obligations, described in section 4.1.6
7. Canadian entitlement returns, described in section 4.1.7
8. Renewable Energy Certificates, described in section 4.1.8
9. other sales, described in section 4.1.9

4.1.1 Priority Firm Power Sales under CHWM Contracts

For FY 2015, the revenues from Priority Firm Power sales pursuant to CHWM contracts are calculated using the product of (1) forecast loads documented in Power Loads and Resources Study § 2.2 and accompanying Documentation Table 1.2.1 for energy, Table 1.2.2 for HLH, and Table 1.2.3 for LLH; and (2) PF-14 rates. Revenues from PF sales pursuant to CHWM contracts for FY 2015 are listed in PRS Table 3, lines 3–12, and in Documentation Table 4.1, lines 3–12.

For FY 2016–2017, revenues from PF sales pursuant to CHWM contracts are computed using the product of (1) forecast loads assuming normal weather, documented in the Power Loads and Resources Study and accompanying Documentation; and (2) the appropriate PF rates derived by RAM2016. Inputs and results for the revenue forecast are managed and calculated pursuant to the CHWM contracts using the Revenue Forecasting Application (RFA). Revenues are reported for Tier 1 Customer charges (Composite, Slice, and Non-Slice), Load Shaping, and Demand, including the Low Density Discount and Irrigation Rate Discount credits, and any additional Tier 2 and/or RSS charges.

4.1.1.1 Composite and Non-Slice Customer Charges

Revenues from each customer for the Composite and Non-Slice Customer charges are based on the customer's TOCA and the customer's contractually specified products. There are no Slice charges for FY 2016–2017. Revenues obtained from the Composite and Non-Slice Customer charges represent the majority of revenues from firm power sales under CHWM contracts for FY 2016–2017. An example calculation of the Composite and Non-Slice charges is available in Documentation Table 4.3. Composite and Non-Slice revenues for FY 2015–2017 are listed in PRS Table 4, lines 3-4, and Documentation Table 4.2, lines 3-4.

4.1.1.2 Load Shaping Charge

The Load Shaping charge reflects the costs and benefits of shaping the Tier 1 System Capability to the monthly and diurnal shape of a customer's below-RHWM load. A charge to the customer results when the customer's shaped load is greater than its share of the Tier 1 System Output in any month for both HLH and LLH; the customer will receive a credit from BPA when the opposite occurs. The Load Shaping charge is described in section 3.1.6.2 above, and an example calculation of the Load Shaping charge is available in Documentation Table 4.4. Load Shaping revenues for FY 2015–2017 are listed in PRS Table 4, line 6, and Documentation Table 4.2, line 6.

4.1.1.3 Demand Charge

The Demand charge is applicable to customers purchasing Load Following or Block with Shaping Capacity products; for FY 2016–2017, there are no customers purchasing Block with Shaping Capacity. The Demand charge is calculated using customer-specific information including actual Customer Tier 1 System Peak, average actual monthly below-HWM load occurring in HLH, Contract Demand Quantities (CDQs), and Super Peak Credit (if applicable). Calculation of a customer's Demand charge is described in section 3.1.6.3 above, and an example calculation is available in Documentation Table 4.4. Demand revenues for FY 2015–2017 are listed in PRS Table 4, line 7, and Documentation Table 4.2, line 7.

4.1.1.4 Irrigation Rate Discount (IRD)

The IRD is a rate credit available to eligible customers and provides a fixed rate discount on Tier 1 rates (the discount does not apply to loads served at Tier 2 rates). May through September eligible irrigation loads are identified in each customer's CHWM contract. The methodology for calculating the IRD end-of-year true-up appears in GRSP II.K.3. Forecast credits for irrigation loads are calculated using an IRD that is derived by multiplying the irrigation loads identified in the CHWM contracts by the IRD rate. The IRD is described in section 3.1.13 above, and an example calculation is available in Documentation Table 4.5. IRD credits for FY 2015–2017 are listed in PRS Table 4, line 8, and Documentation Table 4.2, line 8.

4.1.1.5 Low Density Discount (LDD)

The LDD is prescribed in section 7(d)(1) of the Northwest Power Act and offers a discount of up to 7 percent for customers that meet the criteria specified in GRSP II.M. As set forth in the

TRM, LDD percentages are calculated to provide a discount on power purchased at Tier 1 rates that approximates the discount the customer would have received under non-tiered rates. An example calculation is available in Documentation Table 4.6. LDD credits for FY 2015–2017 are listed in PRS Table 4, line 9, and Documentation Table 4.2, line 9.

4.1.1.6 Tier 2 and Resource Support Services (RSS)

Tier 2 rates are based on a cost allocation that recovers the cost of BPA service to Above-RHWM load. Tier 2 revenues are based on sales to customers that have elected to have BPA serve their Above-RHWM load. Revenues for FY 2015–2017 are listed in PRS Table 4, line 10, and Documentation Table 4.2, line 10.

RSS revenues are based on known services chosen by customers. Revenues for FY 2015–2017 are listed in PRS Table 4, line 11, and Documentation Table 4.2, line 11.

4.1.2 New Resource (NR) Firm Power

Revenues from the NR rate are calculated using the product of (1) forecast IOU or NLSL loads that will be served by BPA at NR rates for FY 2016-2017, documented in the Power Loads and Resources Study, BP-16-FS-BPA-03, § 1.1, and the accompanying Documentation Table 1.1.1; and (2) the appropriate NR rate from RAM2016. For FY 2015, the revenues for power service at NR rates are calculated using the NR-14 rate. Revenues for FY 2015–2017 are listed in PRS Documentation Table 4.1, line 13.

BPA also offers NR products for a customer electing to serve its NLSL(s) with its own dedicated resources. Revenues from these services are based on known services chosen by customers. Revenues for FY 2015–2017 are listed in PRS Table 4, line 13, and Documentation Table 4.1, line 12.

4.1.3 Industrial Firm Power Sales to Direct Service Industrial Customers

BPA sells power to DSIs at the IP rate. Revenues from the IP rate are computed using the product of (1) forecast loads of 312 aMW for FY 2015 and 91 aMW for FY 2016–2017, documented in Power Loads and Resources Study § 2.3 and accompanying Documentation Table 1.2.1 for energy, Table 1.2.2 for HLH, and Table 1.2.3 for LLH, and (2) the appropriate IP rate from RAM2016. For FY 2015, the revenues for DSI customers are calculated using the IP-14 rate. Revenues for FY 2015–2017 are listed in PRS Table 4, line 14, and Documentation Table 4.2, line 14.

4.1.4 Pre-Subscription Sales

During FY 2015–2017, BPA is providing power to one customer under a pre-Subscription contract. The revenues from the pre-Subscription customer are derived by multiplying the individual customer loads by the appropriate FPS rate, both of which are set pursuant to the pre-Subscription contract. Revenues for FY 2015–2017 are listed in PRS Table 4, line 15, and Documentation Table 4.2, line 15.

4.1.5 Short-Term Market Sales

The revenue forecast includes revenues from the sale of surplus energy, which can be a combination of secondary energy and firm energy in excess of that required to serve firm loads. *See* Power Loads and Resources Study, BP-16-FS-BPA-03, § 3.1.2.1.3. The wholesale market price effects of a number of factors are considered in determining the forecast of surplus sales revenue.

For FY 2015, the surplus energy revenue included in the revenue forecast consists of current-year actuals plus the average of the surplus energy revenues in forecast months computed during RevSim simulations of 40 games for each of 80 historical water years, for a total of 3,200 games.

For FY 2016–2017, the surplus energy revenue is the median of the surplus energy revenues across those 3,200 games. In addition, BPA includes an additional credit to account for the incremental value of marketing power to extra-regional points of delivery. *See* Power Risk and Market Price Study, BP-16-FS-BPA-04, § 2.6.3.1.

The revenue forecast for short-term market sales is computed using RevSim to calculate monthly HLH and LLH energy surpluses for each of the 3,200 games, applying corresponding market prices developed for each game. Additionally, the short-term market sales forecast contains revenue from contracted sales for FY 2016–2017. The contracted sales portion consists of premiums from options and sales outside the Pacific Northwest. *See* Power Risk and Market Price Study, BP-16-FS-BPA-04, § 2.6.3.1, and its Documentation, BP-16-FS-BPA-04A, Table 19. Revenues for FY 2015–2017 are shown in PRS Table 4, line 16, and Documentation Table 4.2, line 16.

4.1.6 Long-Term Contractual Obligations

Long-term obligation contracts include the WNP-3 Exchange Settlements, a wind energy exchange, and capacity and energy exchanges. For FY 2015–2017, revenue from these contractual obligations is calculated pursuant to the individual contracts and then summed and added to the forecast as a group. Note that the capacity and energy exchanges do not generate revenue. Revenue for FY 2015–2017 is listed in PRS Table 4, line 17, and Documentation Table 4.2, line 17.

4.1.7 Canadian Entitlement Return

The Canadian Entitlement Return is an obligation for BPA to deliver power to Canada at the border pursuant to Contract No. 99EO-40003. No revenues are generated from the delivery of this power, but energy amounts are listed in the revenue forecast to represent this system obligation. The average megawatt deliveries for FY 2015–2017 are listed in PRS Table 4, line 17, and Documentation Table 4.2, line 18.

4.1.8 Renewable Energy Certificates (RECs)

BPA sells a portion of the RECs it receives as part of its energy purchases from five wind projects. Under the Subscription contracts, 43 preference customers had rights to purchase RECs through FY 2016, of which about half exercised those rights, for an annual average of 9 aMW for FY 2016. The price for the RECs is set outside the rate proceeding pursuant to the terms of the contracts. In May 2011, BPA established the REC prices as $15.00 for FY 2015 and $15.00 for FY 2016. After BPA satisfies these contract obligations, the RECs remaining in BPA's inventory for FY 2016–2017 will be distributed on a pro rata basis to all CHWM customers based on customers' RHWMs. RECs are distributed at no additional charge to the customers and do not generate any revenue for Power Services. Revenues for RECs in FY 2015–2017 are listed in PRS Table 4, line 19, and Documentation Table 4.2, line 19.

4.1.9 Other Sales

Other sales include forecast revenues from the Slice True-Up and Load Shaping True-Up, which are applicable only for FY 2015. Other sales revenue for FY 2015–2017 is listed in PRS Table 4, line 19, and Documentation Table 4.2, lines 23.

4.2 Revenue Forecast for Miscellaneous Revenues

Miscellaneous Revenues include revenues from the General Transfer Agreement (GTA) Service charges, Energy Efficiency, Downstream Benefits, U.S. Bureau of Reclamation (Reclamation) power for irrigation, and the Upper Baker project.

The GTA revenue forecast recovers costs for the delivery of Federal power over non-Federal transmission systems and is described in section 3.6 above. Embedded in the GTA revenue forecast are revenues from the GTA Delivery charge, the Transfer Service Operating Reserve charge, and the Transfer Services WECC and Peak charges, as described in sections 3.6.2 and 3.6.3.

Energy Efficiency revenues are received by BPA as reimbursements for costs relating to implementation of various energy efficiency projects. For FY 2015–2017, revenues from Energy Efficiency are calculated by estimating project expenses. While these revenues are wholly offset by the associated expenses, which are recorded on the expense ledger, the expenses are included in the revenue requirement; therefore, the revenues are included in this forecast.

Downstream Benefits are revenues BPA receives from utilities that benefit from the coordinated planning and operation of Corps of Engineers and Reclamation upstream storage reservoirs as part of the Pacific Northwest Coordination Agreement. For FY 2015–2017, revenues from Downstream Benefits are estimated by applying a forecast of the operations and maintenance costs adjusted for inflation used in the headwater benefit amounts from the most recent study of downstream benefits conducted by the Northwest Power Pool (NWPP).

Reclamation power for irrigation includes power that has been reserved from the FCRPS for use at Reclamation projects. For revenue forecasting purposes, power that has been reserved for Reclamation irrigation projects is classified as either “Reserved Power” or “Irrigation Pumping Power.” Revenue from Reserved Power for FY 2015–2017 is forecast in equal monthly amounts based on an annual amount that is aggregated for Reclamation projects. The annual aggregated amounts are forecast based on historical information provided by Reclamation. Revenue from

Irrigation Pumping Power for FY 2015–2017 is calculated using the forecast irrigation pumping load times the price set in individual contracts.

Finally, revenues from the Upper Baker project are included. Puget Sound Energy keeps 58,000 acre-feet of flood control at this reservoir, which must be held at a lower level during the winter than it would be without flood control, creating head losses. On behalf of the Corps, BPA compensates Puget by delivering non-firm energy and capacity during the flood control season of November through March. In turn, BPA offsets the value of energy and capacity delivered to Puget from the yearly Treasury payment, and the deduction is listed as a revenue receipt from the Corps.

Miscellaneous revenues for FY 2015–2017 are listed in PRS Table 4, line 22, and Documentation Table 4.2, lines 25–31.

4.3 Revenue Forecast for Generation Inputs for Ancillary, Control Area, and Other Services and Other Inter-Business Line Allocations

Power Services receives revenue from Transmission Services for providing generation inputs for ancillary and control area services. The generation inputs cost allocations were agreed upon in the Generation Inputs Partial Settlement. The Settlement sets out the revenue forecast for Regulating Reserves, Variable Energy Resource Balancing Service (VERBS) Reserves, Dispatchable Energy Resource Balancing Service (DERBS) Reserves, Operating Reserves, Synchronous Condensing, Generation Dropping, Redispatch, Segmentation of Corps and Reclamation network and delivery facilities costs, and station service. *See* Settlement Agreement, Appendix A to the Administrator's Final Record of Decision, BP-16-A-02. Revenues are listed in PRS Table 4, line 23, and Documentation Table 4.2, lines 32–51.

4.4 Revenue from Treasury Credits

Revenues are also forecast from two kinds of Treasury credits, or deductions, made from BPA's annual Treasury payment. These credits represent a partial reimbursement by the Treasury for expenses incurred by BPA throughout the year.

4.4.1 Section 4(h)(10)(C) Credits

BPA pays the entirety of the costs relating to the obligations of Northwest Power Act section 4(h)(10)(C) regarding protecting, enhancing, and mitigating fish and wildlife in the region. BPA is reimbursed by the U.S. Treasury for 22.3 percent of the replacement power purchases BPA is expected to make due to fish mitigation, as well as an equal percentage of program and capital expenses related to the fish and wildlife programs. The 22.3 percent represents the non-power portion of the total FCRPS costs, which is the responsibility of taxpayers rather than BPA ratepayers. This credit is treated as Power Services revenue.

Expenses relating to fish and wildlife programs are discussed in Power Revenue Requirement Study § 1.2.1.4. The methodology for estimating the replacement power purchases resulting from changes in hydro system operations to benefit fish and wildlife is described in Power Loads and Resources Study § 3.3.1. The cost of the increased purchases is estimated using RevSim and the market price forecast and is included in the Power Risk and Market Price Study, BP-16-FS-BPA-04, § 2.6.1, and its Documentation, BP-16-FS-BPA-04A, Table 15. Revenue from 4(h)(10)(C) credits is listed in PRS Table 4, line 24, and Documentation Table 4.2, line 52.

4.4.2 Colville Settlement Credits

The Colville Settlement Agreement obligates BPA to make annual payments to the Colville Tribes. BPA receives annual credits from the U.S. Treasury against payments due the U.S. Treasury to defray a portion of the costs of making payments to the Colville Tribes. The

Treasury credit for the Colville Settlement in FY 2016 and FY 2017 is set by legislation at $4.6 million per year. Confederated Tribe of the Colville Reservation Grand Coulee Settlement Act, Pub. L. No. 103-436, 108 Stat. 4577 (Nov. 2, 1994) (as amended). The credit is listed in PRS Table 4, line 25, and Documentation Table 4.2, line 53.

4.5 Power Purchase Expense Forecast

Power Services forecasts three types of power purchase expenses: Augmentation Purchases, Balancing Purchases, and Other Power Purchases. Although most expenses, including some power purchase expenses, such as long-term generating resources, are forecast in the Power Revenue Requirement Study, the power purchase expenses described here are directly related to load, resource, and price assumptions used to develop power rates. Therefore, they are included in the Power Services revenue forecast.

4.5.1 Augmentation Purchase Expense

For planning purposes, the forecast of firm FCRPS output is based upon critical (1937) water conditions. *See* Power Loads and Resources Study, BP-16-FS-BPA-03, § 3.1.2.1.3. The forecast annual firm FCRPS output under critical water plus the output of other Federal resources may not be adequate to meet annual average firm loads. Therefore, system augmentation is added to Federal resources to balance firm annual resources with firm annual loads. The Power Loads and Resources Study projects the need to acquire system augmentation of 0 aMW in FY 2016 and 81 aMW in FY 2017 to meet firm loads. *Id.* § 4.2.

The forecast expense for the augmentation is based on projected prices using the AURORAxmp® model assuming critical water conditions. *See* Power Risk and Market Price Study Documentation, BP-16-FS-BPA-04A, Table 16. Augmentation purchase amounts for FY 2015–2017 are listed in PRS Table 4, line 26, and Documentation Table 4.2, line 55.

4.5.2 Balancing Power Purchases

Balancing power purchases are calculated by RevSim, which finds any monthly HLH and LLH energy deficits by simulations of 40 games in each of the 80 water years, for a total of 3,200 games, and application of the corresponding market prices developed for each game. Similar to the treatment of short-term market sales, the median value for balancing purchases over the 3,200 games is reported for FY 2015 for forecast months and added to actual purchases in past months, and the median value is reported for FY 2016–2017. Total balancing purchase expense for FY 2015–2017 is listed in PRS Table 4, line 27, and Documentation Table 4.2, line 56. A full description is available in the Power Risk and Market Price Study, BP-16-FS-BPA-04, § 2.6.3, and its Documentation, BP-16-FS-BPA-04A, Table 21.

4.5.3 Other Power Purchases

Other power purchases are primarily committed purchases BPA has made to serve preference customer loads in Southeastern Idaho. In those months and water years in which firm loads exceed resources, Southeast Idaho Load Service (SILS) purchases reduce balancing purchases. Conversely, in those months and water years in which resources are sufficient to serve firm loads, SILS purchases increase the amount of surplus sales. RevSim accounts for the energy relating to SILS purchases in the balancing purchases category. However, the amount of expense is included separately as a balancing purchase cost and composite cost. A full description is available in the Power Risk and Market Price Study, BP-16-FS-BPA-04, § 2.6.3.

The cost of Tier 2 power is also included in other power purchases, as are other miscellaneous contracts. Total other power purchase expense for FY 2015–2017 is listed in PRS Table 4, line 28, and Documentation Table 4.2, line 57.

4.6 Summary of Power Revenues

A detailed summary of power revenues at current and proposed rates is available in PRS Tables 3 and 4 and in Documentation Tables 4.1 and 4.2.

5. RATE SCHEDULES

BPA's power rate schedules establish the applicability of each rate schedule to products that BPA offers, the rates for the products, the billing determinants to which the rates are applied, and references to sections of the general rate schedule provisions (GRSPs) that apply to each rate schedule. Note that the General Transfer Agreement Service rate has been moved from the power rate schedules to the power GRSPs; *see* PRS § 3.6.1. The power rate schedules described in this section are presented in their entirety in the BP-16 Power Rate Schedules and General Rate Schedule Provisions.

5.1 Priority Firm Power Rate, PF-16

The PF-16 rate schedule is available for the contract purchase of Firm Requirements Power pursuant to section 5(b) of the Northwest Power Act. Utilities participating in the Residential Exchange Program (REP) under section 5(c) of the Northwest Power Act may purchase PF Power pursuant to a Residential Purchase and Sale Agreement or Residential Exchange Program Settlement Implementation Agreement. *See* Chapter 8 for information on the REP.

5.1.1 Firm Requirements Power under a CHWM Contract

PF Public rates for firm requirements purchases under a CHWM contract include Tier 1 rates, Tier 2 rates, Resource Support Services rates, and Unanticipated Load Service rates. The Tier 1 rates are the three Customer charge rates (Composite, Non-Slice, Slice), Demand rates, and Load Shaping rates. The one-time Slice Billing Adjustment is also included. Tier 2 rates include the Short-Term rate, Load Growth rate, and two Vintage rates, VR1-2014 and VR1-2016. Resource Support Services rates are provided for Diurnal Flattening Service, Resource Shaping, Grandfathered Generation Management Service, and Secondary Crediting Service. The Unanticipated Load Service Charge is applicable to requests for firm requirements service to unanticipated load.

5.1.2 Firm Requirements Power under a Contract other than a CHWM Contract

Rates for firm requirements purchases under other than a CHWM contract include the PF Melded rate and the Unanticipated Load Service rates. The PF Melded rate includes energy and demand rates.

5.1.3 PF Exchange Rates

The PF Exchange rates apply to sales under a Residential Purchase and Sale Agreement or Residential Exchange Program Settlement Implementation Agreement. A utility-specific PF Exchange rate is calculated for each utility purchasing Residential Exchange Program power.

5.2 New Resources Firm Power Rate, NR-16

The NR-16 rate is applicable to sales to investor-owned utilities under Northwest Power Act section 5(b) requirements contracts. The NR-16 rate is also applicable to sales to any public body, cooperative, or Federal agency to the extent such power is used to serve any new large single load, as defined by the Northwest Power Act. The NR-16 rate includes energy and demand rates. The NR rate schedule includes the Energy Shaping Service for NLSLs Charge and the NR Resource Flattening Service Charge. The NR-16 rate schedule also includes the Unanticipated Load Service Charge.

5.3 Industrial Firm Power Rate, IP-16

The IP-16 rate schedule is available for firm power sales to DSIs pursuant to section 5(d) of the Northwest Power Act. The IP-16 rate includes energy and demand rates. DSIs purchasing power pursuant to the IP-16 rate schedule are required to provide the Minimum DSI Operating Reserve – Supplemental.

5.4 Firm Power and Surplus Products and Services Rate, FPS-16

The FPS-16 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, Transmission Scheduling Service/Transmission Curtailment Management Service, Forced Outage Reserve Service, Resource Remarketing Service, Unanticipated Load Service, and other capacity, energy, and power scheduling products and services for use inside and outside the Pacific Northwest. Rates and billing determinants for the products and services sold under the FPS rate schedule are either specified by BPA or mutually agreed upon by BPA and the customer.

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6. GENERAL RATE SCHEDULE PROVISIONS

The GRSPs describe the adjustments, charges, and special rate provisions applicable to BPA's rate schedules. The GRSPs also define the power products and services BPA offers, and define other applicable terms. This section includes brief descriptions of provisions that are not described elsewhere in the study. The GRSPs described in this section are presented in their entirety in the BP-16 Power Rate Schedules and General Rate Schedule Provisions.

6.1 Supplemental Guidelines for Direct Assignment of Facilities Costs Incurred Under Transfer Agreements

The Supplemental Guidelines address how BPA will recover the costs for facility expansions and upgrades on third-party transmission systems for transfer service customers. The Supplemental Guidelines, in conjunction with the Transmission Services Facility Ownership and Cost Assignment Guidelines, are used to determine whether and in what way specific facility or expansion costs should be assigned to particular transfer service customers. *See* GRSP I.E.

6.2 Conservation Surcharge

Section 7(h) of the Northwest Power Act states that BPA may apply to rates a surcharge recommended by the Northwest Power and Conservation Council pursuant to section 4(f)(2) of the Northwest Power Act. BPA does not currently anticipate applying such a surcharge in the FY 2016–2017 rate period. *See* GRSP II.A.1.

6.3 Large Project Targeted Adjustment Charge

The Large Project Targeted Adjustment Charge (LPTAC) recovers costs from BPA making funds available for the acquisition of conservation supporting a Large Project Program (LPP). At any time during the rate period, a customer may submit a project to BPA for consideration of funding through the LPP. Customers will be charged the True Acquisition Cost associated with the funding. *See* GRSP II.A.2.

6.4 Cost Contributions

Section 7(j) of the Northwest Power Act states that BPA's rate schedules must indicate the approximate cost contributions of different resource categories to BPA's rates for the sale of energy and capacity. The rate schedules also must indicate the cost of resources BPA acquires to meet load growth and the relationship of such cost to BPA's average resource cost. *See* GRSP II.B.

6.5 Cost Recovery Adjustment Clause (CRAC)

The CRAC is a mechanism that results in an upward rate adjustment to respond to the financial risks BPA faces before BPA can conduct a section 7(i) rate proceeding to adjust its rates. If stated conditions are met, the CRAC will trigger and a rate increase will go into effect beginning on October 1 of the applicable year. *See* GRSP II.C and Power Risk and Market Price Study, BP-16-FS-BPA-04, § 3.2.3.

6.6 Dividend Distribution Clause (DDC)

The DDC is a mechanism that results in a downward rate adjustment to return accumulated net revenues to customers when BPA's cash reserves exceed a pre-defined level. If stated conditions are met, the DDC will trigger and a rate decrease will go into effect beginning on October 1 of the applicable year. *See* GRSP II.E and Power Risk and Market Price Study, BP-16-FS-BPA-04, § 3.2.5.

6.7 DSI Reserves

In the event that BPA agrees to acquire an additional reserve product from a DSI, this provision (1) establishes the mechanism through which BPA compensates the DSI and (2) places a cap on the unit price of any reserve product to be purchased to ensure that the reserve acquisition is cost effective. *See* GRSP II.F.

6.8 Flexible New Resource Firm Power Rate Option

The Flexible NR rate option, offered at BPA's discretion, allows NR-16 rates and billing determinants to be modified to accommodate a customer's request to change the way power is charged under the NR-16 rate schedule. The GRSP describes the factors that will be considered in such modifications. *See* GRSP II.H.

6.9 Flexible Priority Firm Power Rate Option

The Flexible PF rate option, offered at BPA's discretion, allows PF-16 rates and billing determinants to be modified to accommodate a customer's request to change the way power is charged under the PF-16 rate schedule. The GRSP describes the factors that will be considered in such modifications. *See* GRSP II.I.

6.10 The NFB Mechanisms

There are two NFB mechanisms, which allow BPA to recover additional revenue if financial impacts from a specified set of circumstances in the fish and wildlife arena cause a reduction in Power Services' forecast net revenue. The first mechanism, the NFB Adjustment, could result in an increase in the maximum revenue recoverable under a CRAC. The second mechanism, the Emergency NFB Surcharge, could result in a rate increase within the fiscal year. *See* GRSP II.N and the Power Risk and Market Price Study, BP-16-FS-BPA-04, § 4.2.

6.11 Priority Firm Power (PF) Shaping Option

If requested, BPA will, to the maximum extent practicable while ensuring timely BPA cost recovery, accommodate individual customer requests to reshape charges within each year of the rate period to mitigate adverse cash flow effects on the customer. Such reshaping of charges must recover the same number of dollars on a net present value basis within the fiscal year as would have been recovered without the reshaping. The reshaping of the payments will be agreed upon between BPA and the customer prior to the start of the rate period. *See* GRSP II.P.

6.12 Remarketing

The Remarketing credit conveys the value BPA receives when it remarkets committed Tier 2 purchases in excess of need and non-Federal resources to which Diurnal Flattening Service applies that are temporarily in excess of need. The excess is created when commitments to purchase are made prior to establishing need in the RHWM Process. *See* GRSP II.R.

6.13 REP 7(b)(3) Surcharge Adjustment

The REP 7(b)(3) surcharge is a utility-specific addition to one of the Base PF Exchange rates that recovers each REP participant's allocated share of rate protection provided pursuant to section 7(b)(2) of the Northwest Power Act. Each REP participant's initial 7(b)(3) surcharge is determined in a section 7(i) rate proceeding based on a Base PF Exchange rate and the ASCs and forecast exchange loads of all utilities assumed for ratemaking to participate in the REP. Each REP participant's initial 7(b)(3) surcharge is displayed in section 6.1 of the PF-16 rate schedule. Each 7(b)(3) surcharge is subject to change during the rate period if any participant's ASC changes during the rate period due to the addition or removal of a resource from the participant's resource portfolio or the planned addition of a new large single load in the service territory of the participant. The procedures for modifying the 7(b)(3) surcharges of all REP participants are codified in GRSP II.T.

6.14 TOCA Adjustment

For each customer purchasing Firm Requirements Power under a CHWM contract, a TOCA for each year of the rate period is calculated in the BP-16 7(i) process. A customer's TOCA for a fiscal year may be adjusted to account for a significant change in the customer's total load, as detailed in GRSP II.Y, or for a mid-year change to a customer's annual net requirement.

6.15 Unanticipated Load Service

Unanticipated Load Service (ULS) applies to any request for Firm Requirements Power received after February 1, 2015, that results in an unanticipated increase in a customer's load placed on BPA during the FY 2016–2017 rate period. Contractual obligations that result from a request for service under section 9(i) of the Northwest Power Act also will be considered ULS. ULS also may apply to a customer that adds load through retail access, including load that was once served by the customer and returns under retail access. *See* GRSP II.Z.

6.16 Unauthorized Increase Charges

The Unauthorized Increase (UAI) charge is a penalty charge to customers taking more power from BPA than they are contractually entitled to take. The UAI demand rate is 1.25 times the applicable monthly demand rate. The UAI energy rate is the greater of 150 mills/kWh or two times the highest hourly Powerdex Mid-C Index price for firm power for the month. *See* GRSP II.AA.

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7. SLICE TRUE-UP

7.1 Slice True-Up Adjustment

Slice customers are subject to 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 will be calculated for each fiscal year as soon as BPA's audited actual financial data are available (usually in November). *See* TRM, BP-12-A-03, § 2.7.

7.2 Composite Cost Pool True-Up

The Composite Cost Pool True-Up is the calculation of the annual Slice True-Up Adjustment for the Composite Cost Pool for each fiscal year. For each Slice customer, the annual Slice True-Up Adjustment Charge for the Composite Cost Pool will be calculated as shown in GRSP II.W.1. The dollar amount calculated may be positive or negative. The Composite Cost Pool True-Up Table (GRSP II.W, Table G) shows the forecast expenses, revenue credits, and adjustments that form the basis for the Slice True-Up Adjustment calculation for the Composite cost pool for the applicable fiscal year.

The following sections discuss the treatment of certain expenses, revenue credits, and adjustments included in the Composite Cost Pool True-Up.

7.2.1 System Augmentation Expenses

System augmentation expenses are included in the FY 2016–2017 Composite cost pool. Some of these augmentation expenses are a cost for service to Non-Slice customers' Above-RHWM load that is served at Load Shaping rates. For a description of these system augmentation expenses, *see* section 3.1.3.3 above.

System augmentation expenses are not subject to the Composite Cost Pool True-Up. However, implicit in the Composite Cost Pool True-Up of the firm surplus and secondary adjustment for Unused RHWM and the DSI revenue credit are adjustments that reflect the effects of additional power purchases (or lack thereof) or additional power sales to the market. Sections 3.1.3.2, 7.2.3, and 7.2.4 describe the treatment of the firm surplus and secondary adjustment for unused RHWM and the DSI revenue credit for Composite Cost Pool True-Up purposes.

BPA's purchase of output from the Klondike III resource is a Tier 1 augmentation expense, and the Composite cost pool includes the cost of Resource Support Services and Resource Shaping Charges to shape the generation output of Klondike III into a flat annual block of power. Because the RSS and RSC charges financially convert the variable output of Klondike III to a firm annual block of power and are committed to in advance, the augmentation expense and RSS and RSC costs associated with generation output from the Klondike III resource are not subject to the Composite Cost Pool True-Up.

7.2.2 Balancing Augmentation Load Adjustment

The Balancing Augmentation Load Adjustment can result in a positive or negative credit to the Composite cost pool. Section 3.1.3.3 above describes the Balancing Augmentation Load Adjustment, the circumstances that would result in a credit, and the circumstances that would result in a negative credit. The Balancing Augmentation Load Adjustment is not subject to the Composite Cost Pool True-Up.

7.2.3 Firm Surplus and Secondary Adjustment from Unused RHWM

The Firm Surplus and Secondary Adjustment from Unused RHWM is subject to the Composite Cost Pool True-Up. *See* GRSP II.W.1.(a). This adjustment reflects the fact that when the sum of actual TOCAs is greater than the sum of forecast TOCAs, additional power is sold to customers at the Composite Customer rate, and it is assumed that additional costs are incurred in the form of forgone market sales or increased power purchases. Likewise, when the sum of actual TOCAs is less than the sum of forecast TOCAs, less power is sold to customers at the Composite Customer rate, and it is assumed that more power is sold in the market or fewer power purchase costs are incurred.

7.2.4 DSI Revenue Credit

The forecast costs associated with service to the DSIs are included in the Composite cost pool. *See* TRM, BP-12-A-03, § 3.2.1.3. DSI revenues received by BPA are included in the Composite cost pool as credits. The DSI Revenue Credit is subject to the Composite Cost Pool True-Up. *See* GRSP II.W.1.(b).

The calculation of the DSI revenue credit starts with the forecast DSI revenue credit, which then is adjusted to calculate the actual DSI revenue credit. When actual DSI sales are greater than the rate case forecast DSI sales, it is assumed that additional power is sold to the DSIs at the IP rate and additional costs are incurred in the form of forgone market sales or increased power purchases. The adjustment to the forecast DSI revenue credit reflects the revenues from the additional power sold to the DSIs and the additional costs that are incurred. Likewise, when actual DSI sales are less than the rate case forecast DSI sales, it is assumed that less power is sold to DSIs at the IP rate and more power is sold in the market, or it is assumed that such power may be used to meet BPA obligations so that fewer power purchase costs are incurred. The adjustment to the forecast DSI revenue credit reflects these effects. The adjustment also includes any DSI take-or-pay revenues recorded by BPA, if applicable.

7.2.5 Interest Earned on the Bonneville Fund

On the first day of the Slice contract, October 1, 2001, BPA had $495.6 million in financial reserves attributed to the Power function. TRM section 2.5 provides for an interest credit that BPA will allocate to the Composite cost pool based on the pre-FY 2002 level of reserves. TRM section 2.5 further provides that future circumstances may occur that make it reasonable and fair to make adjustments to the size of the base amount of financial reserves attributed to the Power function as of October 1, 2001, for purposes of calculating the interest credit allocated to the Composite cost pool.

BPA made several adjustments to the base reserve amount in setting the BP-14 rates, as shown on PRS Table 5. The adjustments reflected in Table 5 are not amounts that have been shared with or collected from Slice customers through a prior Slice True-Up. As a result, these amounts are reflected as adjustments to the size of the base amount of financial reserves. As shown on Table 5, the revised reserve amount for purposes of calculating the interest credit is $570.26 million. BPA has not made any adjustments to the revised reserve amount from BP-14 in setting the BP-16 rates. The forecast interest credit for the Composite cost pool is $8.44 million in FY 2016 and $15.23 million in FY 2017.

The interest credit on the financial reserves amount is subject to the Composite Cost Pool True-Up. The actual interest credit calculated on the revised base amount of financial reserves can change from the forecast interest credit if there are changes in the factors used to calculate the forecast interest credit. *See* Revenue Requirement Study Documentation, BP-16-FS-BPA-02A, § 5, for a description of how the interest credit calculation factors can change.

7.2.6 Prepay Offset Credit

The Prepay Offset Credit represents the interest income earned on the power prepayment funds deposited in the Bonneville Fund in FY 2013 and in applicable future fiscal years. The power prepayment funds are being applied toward capital spending on the Federal hydro maintenance program, the cost of which is included in the Composite cost pool. Because BPA received the proceeds of the prepayment program in advance of their expenditure, interest income will accrue in the Bonneville Fund. The Prepay Offset Credit is included in the calculation of net interest expense in the Composite cost pool table, GRSP Table G. *See* BP-14 Final ROD, BP-14-A-03, § 2.3.3. In the Slice True-Up process, the Prepay Offset Credit will be trued up annually to ensure that the amount of credit reflects the actual amount of interest earned on the prepay funds. *See* Power Revenue Requirement Study Documentation, BP-16-FS-BPA-02A, § 5,Table 5A, for forecast amounts.

7.2.7 Bad Debt Expenses

Bad debt expenses, if any, are allocated between the Composite cost pool and the Non-Slice cost pool, as specified in TRM Table 2A. There is no forecast bad debt expense for the FY 2016–2017 period for ratesetting purposes. If a bad debt expense is identified and accounted for in BPA's actual audited financial reports for a given fiscal year, BPA will determine whether the expense should be included in the actual expenses and revenue credits that are allocable to the Composite cost pool in the applicable fiscal year of the rate period. If so, then the expense may be included for purposes of the Composite Cost Pool True-Up, and the bad debt expense would be allocated according to the principle of cost causation, as described generally in TRM, BP-12-A-03, section 2.1.

Any bad debt expense associated with a sale to any customer that purchased Federal power exclusively at the FPS-14 and FPS-16 rates would be excluded for Composite Cost Pool True-Up purposes. Bad debt expenses associated with sales of power at only these FPS rates are related solely to BPA's sales of surplus power after the inception of the Slice product and not to sales of requirements power. The expenses and revenues from such sales are included in the Non-Slice cost pool. *See* TRM, BP-12-A-03, § 2.2.3.

Any bad debt expense associated with a sale to a customer that purchases power at only the PF or IP rate will be included for purposes of the Composite Cost Pool True-Up. The allocation to the Composite cost pool of any bad debt expense associated with a sale to a customer that purchases power at both the PF rate and the FPS rate, or a sale to a customer that purchases power at both the IP rate and the FPS rate, will be contingent on the circumstances of the particular instance of a full or partial non-payment of a power bill.

Revenue recoveries of bad debt expenses will be included for Composite Cost Pool True-Up purposes if Slice customers paid for the bad debt expense through their Slice True-Up Adjustment Charge.

7.2.8 Settlement and Judgment Amounts

BPA payments or receipts of money related to settlements and judgments will be allocated on a case-by-case basis to either the Composite cost pool or the Non-Slice cost pool. If an amount (payment or receipt) is accounted for in BPA's actual audited financial reports for any given fiscal year (reports are produced after rates are set), BPA will determine whether such amount will be included or excluded for Composite Cost Pool True-Up purposes. Such a determination will be made based on the principle of cost causation. *See* TRM, BP-12-A-03, § 2.1.

7.2.9 Transmission Costs for Designated BPA System Obligations

Transmission and Ancillary Services expenses are allocated between the Composite cost pool and the Non-Slice cost pool, as specified on TRM, BP-12-A-03, Table 2A.
The Transmission and Ancillary Services expenses associated with Designated BPA System Obligations are allocated to the Composite cost pool. Such Transmission and Ancillary Services expenses are not subject to the Composite Cost Pool True-Up.

Transmission reservations are set aside for non-discretionary obligations (*i.e.*, Designated BPA System Obligations). Because Power Services does not know the actual amounts of transmission usage until the preschedule period for such obligations, the transmission reservations for those obligations are purchased based on the maximum need for the year. Therefore, it is appropriate to include the forecast cost of the reservations for Designated BPA System Obligations in the Composite cost pool, and such costs are not subject to the Composite Cost Pool True-Up.

Any revenues from the resale of transmission that appear to be the result of BPA sales of unused transmission inventory associated with set-aside transmission will be excluded for Composite Cost Pool True-Up purposes. Such revenues are excluded from the Composite Cost Pool True-Up to be consistent with the principle of no Composite Cost Pool True-Up of transmission expenses for Designated BPA System Obligations. Because the cost of additional transmission purchased (or of using Non-Slice transmission inventory) to serve Designated BPA System Obligations in excess of what was forecast in the ratesetting process is not included in the Composite Cost Pool True-Up, revenues from sales of surplus transmission inventory also are excluded from the Composite Cost Pool True-Up.

7.2.10 Transmission Loss Adjustment

A transmission loss adjustment is included in the Composite cost pool. Without such an adjustment, Slice customers would pay not only for real power losses (through loss return schedules to BPA) on the transmission of their Slice purchase, but also a proportionate share of losses on the transmission of non-Slice products. *See* section 3.1.3.1 above for an explanation of the calculation of this credit.

The transmission loss adjustment is not subject to the Composite Cost Pool True-Up.

7.2.11 Resource Support Services Revenue Credit

A credit for RSS revenue is included in the Composite cost pool. The credit is for revenues earned by uses of capacity to support resources that receive RSS. *See* § 3.1.2.1. This revenue credit is not subject to the Composite Cost Pool True-Up.

7.2.12 Generation Inputs for Ancillary and Other Services Revenue Credit

A credit for Generation Inputs for Ancillary and Other Services revenue is included in the Composite cost pool. The credit is for revenues earned from the use of capacity and energy in meeting BPA's Designated System Obligations that are Generation Inputs. Included are revenues from Transmission Services for Generation Imbalance, Energy Imbalance, and Operating Reserves energy. *See* TRM, BP-12-A-03, Table 2, line 120, and Table 3.4, line 44. This revenue credit is subject to the Composite Cost Pool True-up.

7.2.13 Tier 2 Rate Adjustments

Tier 2 rate adjustments are ratesetting adjustments to the Composite cost pool to reflect a share of expenses incurred by Power Services that are allocable to all power sold. *See* § 3.1.4. There are three types of rate adjustments: the Tier 2 overhead cost adder, the Tier 2 risk adder, and the Tier 2 transmission scheduling service cost adder.

The Tier 2 overhead cost adder is an adjustment for administrative costs incurred by Power Services. *See* § 3.1.7.1. The Tier 2 overhead cost adder is included in the Composite cost pool. This adjustment is estimated for ratesetting purposes and is not subject to the Composite Cost Pool True-Up.

The Tier 2 risk adder is an adjustment for any risks associated with costs of resources that Power Services acquires for service to Tier 2 load. This adjustment is zero for the FY 2016–2017 rate period because no risk mitigation treatment is necessary. *See* § 3.1.7.4. This adjustment is not subject to the Composite Cost Pool True-Up.

The Tier 2 Transmission Scheduling Service cost adder is an adjustment for administrative costs incurred by Power Services. For a description of this adjustment see section 3.1.7.2. The forecast of this adjustment is included in the RSS revenue credit. This adjustment is not subject to the Composite Cost Pool True-Up.

7.2.14 Residential Exchange Program Expense

Forecast REP benefits are included in the Composite cost pool for ratesetting purposes. The forecast of REP expense on the Composite Cost Pool True-Up Table is equal to the forecast of REP benefits expected to be paid to REP participants. The forecast REP expense is subject to the Composite Cost Pool True-Up.

7.2.15 Canadian Designated System Obligation Annual Financial Settlements

The Non-Treaty Storage Agreement (NTSA) is an agreement between BPA and B.C. Hydro that allows water transactions to be financially settled between them. The NTSA provides two mechanisms to settle the transaction benefits, which BPA designates as a system obligation: (1) energy deliveries during the year, and (2) a financial settlement based on the August 31 balance at the end of the year. The Short-Term Libby Agreement (STLA) and subsequent updates are agreements between the U.S. and Canada that allow water transactions to be financially settled between BPA, acting on behalf of the U.S., and B.C. Hydro, acting on behalf of Canada. The STLA does not have a provision to settle transactions by energy delivery. BPA designates the STLA as a system obligation, and the financial settlement is based on the August 31 balance at the end of the year. Financial settlements in a fiscal year and the financial accrual amount recorded for the month of September in a fiscal year are charged or credited to other power purchases, and Slice customers pay their share of the charge or receive their share of the credit through the Composite Cost Pool True-Up Table.

7.2.16 Other Adjustments

Two new line items are added to the Composite cost pool table. The first is the “PGE WNP3 Settlement” line item in the MRNR calculation. *See* GRSP II.W, Table G, line 142. In 1998, BPA and PGE entered into a settlement of a WNP-3 Exchange contract. PGE paid BPA $74 million to settle the contract. The funds from the settlement were deposited in the BPA Fund in 1998. Although all the funds were received in 1998, for accounting purposes BPA is recognizing these revenues over the remaining life of the contract, starting in 1998 and continuing to the end of the original exchange contract in 2019. This results in $3.524 million per year of revenue. The annual recognition is considered a non-cash transaction because the cash was received with the signing of the settlement in 1998. The line item “PGE WNP3 Settlement” allocates the non-cash revenues from the PGE Settlement to the Composite cost pool. Including this line item ensures that the balance between benefits and costs related to the PGE Settlement will be allocated equitably between Slice and Non-Slice customers. The PGE Settlement is not subject to the Composite Cost Pool True Up.

The second new line item is the “Expense Offset” line item in the Other Income, Expense, and Adjustment section of the cost table (GRSP II.W, Table G, line 80). As described in the IPR2 Final Close-out Report (May 2015), BPA plans to use cash flows resulting from an extension of maturing CGS debt that is currently related to Debt Service Reassignment for two purposes. One purpose is to accelerate an existing plan for repayment of Federal appropriations. The other purpose is to mitigate the rate impact of transitioning from a capitalized Energy Efficiency investment program to one that is fully expensed. The cash resulting from these debt management actions is included in the “Expense Offset” line item. Without the new line item, BPA would not be able to mitigate the impact of accelerating appropriations repayment or expensing the EE investment program in a way that ensures the equitable treatment of Slice and Non-Slice customers. The Expense Offset is subject to the Composite Cost Pool True-Up.

7.3 Slice Cost Pool True-Up

The Slice Cost Pool True-Up is the calculation of the annual Slice True-Up Adjustment for the Slice cost pool, as described in TRM section 2.72. Calculation of the Annual Slice Cost Pool True-Up is described in GRSP II.W.2 and is shown in GRSP Table H. Slice expenses and credits are forecast to be zero in FY 2016–2017. If there are any actual Slice expenses and credits incurred during the rate period, such expenses and credits will be subject to the Slice Cost Pool True-Up.

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8. AVERAGE SYSTEM COSTS

8.1 Overview of the Residential Exchange Program (REP)

The Residential Exchange Program, established by section 5(c) of the Northwest Power Act, was designed to provide residential and farm customers of Pacific Northwest utilities a form of access to low-cost Federal power. Under the REP, BPA purchases power (which for ratesetting is called exchange resources) from each participating utility at that utility's average system cost (ASC). BPA offers, in exchange, to sell the utility an equivalent amount of electric power (which for ratesetting is called exchange loads) at BPA's Priority Firm Power Exchange (PFx) rate. The "exchange" transfers no actual power to or from BPA; it is an accounting transaction in which dollars are exchanged rather than electric power. However, to ensure proper cost allocations and rate determinations, RAM2016 models the REP as a purchase of power by BPA (priced at the participants' respective ASCs) and a simultaneous sale of power to the REP participants (priced at the participants' respective PFx rates).

BPA is implementing the 2012 REP Settlement with investor-owned utility (IOU) exchange participants and concurrent REP settlements with participating consumer-owned utilities (COUs) in rates for FY 2016–2017. The 2012 REP Settlement establishes a fixed stream of REP benefits that are payable to the IOU exchange participants beginning in FY 2012 and ending in FY 2028. Individual IOU REP benefit determinations under the 2012 REP Settlement will continue as under the traditional REP. That is, BPA will compare the IOUs' respective ASCs for FY 2016–2017 with their respective BP-16 PF Exchange rates and, if the difference is positive, multiply the difference by the IOUs' exchange loads to calculate their REP benefits (in dollars). Similarly, pursuant to the REP settlements with the two COUs participating in the REP, BPA will compare their respective ASCs for FY 2016–2017 with their respective BP-16 PF Exchange rates and, if the difference is positive, multiply the difference by their exchange loads to calculate their REP benefits. The COUs' REP benefits are in addition to (*i.e.*, are not included in) the fixed stream of IOU REP benefits under the 2012 REP Settlement. For a forecast of individual utility annual REP benefit payments for FY 2016–2017, see Table 6.

8.2 ASC Determinations

The participating utilities' ASCs are determined outside the rate proceeding in an ASC Review Process that BPA conducts pursuant to the substantive and procedural requirements of the 2008 ASC Methodology (ASCM). *See* 2008 ASCM, 18 C.F.R. § 301, *et seq*. The Federal Energy Regulatory Commission granted final approval to the 2008 ASCM on September 4, 2009.

A utility's ASC for the rate period is calculated by dividing the utility's allowable resource costs (Contract System Cost) by its allowable load (Contract System Load). The quotient is the utility's rate period ASC ($/MWh). Contract System Cost is the sum of the utility's allowable generation-related and transmission-related costs and overheads. Contract System Load is calculated as the total retail sales of a utility as measured at the meter, plus distribution losses, less any new large single loads (NLSLs), if applicable.

The ASCs used in the BP-16 Final Proposal were determined in Final ASC Reports published on July 23, 2015. The Final ASC Reports establish the utilities' ASCs for the BP-16 rate period. Final ASC Reports were issued for eight utilities: Avista Utilities, Idaho Power Company, NorthWestern Energy, PacifiCorp, Portland General Electric, Puget Sound Energy, Clark County PUD, and Snohomish County PUD.

Under the 2008 ASCM, the actual ASC for each utility may change if the utility adds a new resource, retires an existing resource, or adds an NLSL. The revised ASC takes effect in the month after a new resource comes on line, an existing resource is retired, or a new NLSL begins taking service. Power GRSP II.T.1 specifies how PF Exchange rates applicable to each REP participant will change if a revised ASC takes effect.

Under the 2012 REP Settlement, participating IOUs agreed not to submit ASC revisions based on new resources coming on line or being removed during the Exchange Period (the Exchange Period is the same as the rate period). Under the 2012 REP Settlement, the ASCs that are effective on the first day of the rate period will continue to be in effect throughout the Exchange Period. Therefore, "day-one" IOU ASCs are developed for use in establishing rates under the REP Settlement.

Three IOUs (Portland General Electric, PacifiCorp, and NorthWestern Energy) have new resources that began operation prior to the start of the BP-16 Exchange Period. Therefore, the day-one ASCs used for the BP-16 Final Proposal include the costs of these new resources. Snohomish County PUD, which is not a party to the IOU agreement not to submit new resources, has a group of new resources that is scheduled to come on-line in late FY 2017 that will result in a revised ASC for Snohomish at that time. The ASCs for the BP-16 rate period are shown in Documentation Table 8.2.

8.3 BP-16 Residential and Farm Exchange Loads

Exchange loads are defined as a utility's qualifying residential and farm consumer loads as determined in accordance with the utility's Residential Purchase and Sale Agreement or Residential Exchange Program Settlement Implementation Agreement.

Under the 2012 REP Settlement, participating IOUs agreed to use a two-year historical average for determining the monthly exchange load, referred to as Residential Load, to calculate IOU REP benefits. For the BP-16 rate period, the historical years are calendar year (CY) 2013 and

CY 2014. The monthly loads applicable to both years of the BP-16 rate period are shown in GRSP II.S., Table E.

The COU REP settlements do not specify the use of historical exchange loads in computing COU REP benefits; therefore, forecasts are used to estimate COU REP benefits for ratemaking purposes. For the COUs, the FY 2016–2017 exchange load forecasts are based on the exchange load information provided by the COUs in the ASC Review Process. Each COU's exchange load forecast is adjusted for the COU's Tier 1 percentage, as required by the TRM. The Tier 1 percentage is defined as BPA's forecast percentage of the COU's load that is expected to be served by purchases of power at Tier 1 rates from BPA and from the COU's Existing Resources for CHWM. COU REP benefits will be paid on actual residential and farm sales as adjusted by the Tier 1 percentage for each COU, as submitted after the conclusion of each month during the rate period. The monthly IOU Residential Loads and monthly forecast COU exchange loads are shown in Documentation Table 8.1.

POWER RATES TABLES

Table 1: Rate Period High Water Marks for FY 2016-2017

	A	B
	Preference Customer	**RHWM (aMW)**
1	Albion, City of	0.394
2	Alder Mutual Light Company	0.542
3	Ashland, City of	20.863
4	Asotin County PUD	0.568
5	Bandon, City of	7.565
6	Benton County PUD	199.617
7	Benton Rural Electric Association	66.081
8	Big Bend Electric Cooperative, Inc.	60.597
9	Blachly-Lane Electric Cooperative	17.444
10	Blaine, City of	8.661
11	Bonners Ferry, City of	5.268
12	Burley, City of	13.927
13	Canby Utility	20.111
14	Cascade Locks, City of	2.354
15	Central Electric Cooperative, Inc.	81.052
16	Central Lincoln People’s Utility District	155.144
17	Centralia, City of	24.134
18	Cheney, City of	15.663
19	Chewelah, City of	2.743
20	Clallam County PUD No. 1	75.286

	A	B
	Preference Customer	**RHWM (aMW)**
21	Clark Public Utilities	315.386
22	Clatskanie People's Utility District	91.932
23	Clearwater Power Company	23.646
24	Columbia Basin Electric Cooperative, Inc.	12
25	Columbia Power Cooperative Association	3.203
26	Columbia River People's Utility District	57.682
27	Columbia Rural Electric Cooperative, Inc.	37.325
28	Consolidated Irrigation District #19	0.225
29	Consumers Power, Inc.	45.228
30	Coos-Curry Electric Cooperative, Inc.	40.476
31	Coulee Dam, Town of	2.001
32	Cowlitz County PUD	543.84
33	Declo, City of	0.355
34	DOE National Energy Technology Laboratory	0.454
35	DOE Richland	26.034
36	Douglas Electric Cooperative, Inc.	18.357
37	Drain, City of	1.896
38	East End Mutual Electric Co., Ltd.	2.661
39	Eatonville, Town of	3.335
40	Ellensburg, City of	23.748
41	Elmhurst Mutual Power & Light Company	31.924
42	Emerald People's Utility District	49.47

	A	B
	Preference Customer	**RHWM (aMW)**
43	Energy Northwest	2.764
44	Eugene Water and Electric Board	248.647
45	Fairchild Air Force Base	6.042
46	Fall River Rural Electric Cooperative, Inc.	32.807
47	Farmers Electric Company	0.502
48	Ferry County PUD No. 1	11.551
49	Flathead Electric Cooperative, Inc.	165.195
50	Forest Grove, City of	26.422
51	Franklin County PUD No. 1	116.206
52	Glacier Electric Cooperative, Inc.	21.109
53	Grant County PUD No. 2 – Grand Coulee	5.141
54	Grays Harbor County PUD No. 1	129.936
55	Harney Electric Cooperative, Inc.	22.531
56	Hermiston, City of	12.811
57	Heyburn, City of	4.77
58	Hood River Electric Cooperative	12.971
59	Idaho County Light & Power Coop.	6.153
60	Idaho Falls Power	78.78
61	Inland Power & Light Company	106.69
62	Jefferson County PUD No. 1	44.732
63	Kittitas County PUD No. 1	9.608
64	Klickitat County PUD	36.301

	A	B
	Preference Customer	**RHWM (aMW)**
65	Kootenai Electric Cooperative, Inc.	50.502
66	Lakeview Light & Power	32.79
67	Lane Electric Cooperative, Inc.	28.819
68	Lewis County PUD No. 1	112.623
69	Lincoln Electric Cooperative, Inc.	13.864
70	Lost River Electric Cooperative, Inc.	9.433
71	Lower Valley Energy	85.198
72	Mason County PUD No. 1	8.899
73	Mason County PUD No. 3	79.149
74	McCleary, City of	3.681
75	McMinnville Water and Light	87.318
76	Midstate Electric Cooperative, Inc.	46.29
77	Milton-Freewater, City of	10.353
78	Milton, City of	7.364
79	Minidoka, City of	0.117
80	Mission Valley Power	37.582
81	Missoula Electric Cooperative, Inc.	26.722
82	Modern Electric Water Company	26.028
83	Monmouth, City of	8.282
84	Nespelem Valley Electric Cooperative, Inc.	5.824
85	Northern Lights, Inc.	35.577
86	Northern Wasco County PUD	64.133

	A	B
	Preference Customer	**RHWM (aMW)**
87	Ohop Mutual Light Company	10.059
88	Okanogan County Electric Coop, Inc.	6.465
89	Okanogan County PUD No. 1	45.463
90	Orcas Power and Light Cooperative	24.493
91	Oregon Trail Electric Consumers Cooperative, Inc.	78.409
92	Pacific County PUD No. 2	35.973
93	Parkland Light and Water Company	13.931
94	Pend Oreille County PUD No. 1	25.517
95	Peninsula Light Company, Inc.	71.283
96	Plummer, City of	3.907
97	Port Angeles, City of	84.646
98	Port of Seattle	17.11
99	Raft River Rural Electric Cooperative, Inc.	36.245
100	Ravalli County Electric Cooperative, Inc.	18.334
101	Richland, City of	102.542
102	Riverside Electric Company	2.349
103	Rupert, City of	9.33
104	Salem Electric	38.313
105	Salmon River Electric Cooperative	31.082
106	Seattle City Light	518.799
107	Skamania County PUD No. 1	15.751
108	Snohomish County PUD No. 1	791.273

	A	B
	Preference Customer	**RHWM (aMW)**
109	Soda Springs, City of	3.007
110	South Side Electric, Inc.	6.699
111	Springfield Utility Board	99.723
112	Steilacoom, Town of	4.761
113	Sumas, City of	3.607
114	Surprise Valley Electric Corp.	16.272
115	Tacoma Public Utilities	398.464
116	Tanner Electric Cooperative	10.925
117	Tillamook People's Utility District	55.482
118	Troy, City of	2.018
119	U.S. Dept of the Navy – Bremerton	30.162
120	U.S. Dept of the Navy – Everett	1.512
121	U.S. Dept. of the Navy – Bangor	20.222
122	Umatilla Electric Cooperative	112.118
123	Umpqua Indian Utility Cooperative	4.073
124	United Electric Cooperative, Inc.	29.684
126	Vera Water & Power	26.892
127	Vigilante Electric Cooperative, Inc.	18.965
128	Wahkiakum County PUD No. 1	4.956
129	Wasco Electric Cooperative, Inc.	13.265
130	Weiser, City of	6.267
131	Wells Rural Electric Company	94.837

	A	B
	Preference Customer	**RHWM (aMW)**
132	West Oregon Electric Cooperative, Inc.	8.399
133	Whatcom County PUD No. 1	26.571
134	Yakama Power	11.52
135	**Total (equal to the RHWM Tier 1 System Capability)**	**6983.084**

Table 2: Overview of BP-16 Final Proposal Rates

	A	B		C	D
1				% Change BP-14	
2	Unbifurcated PF	$	43.35	3.6%	
3	PF Public (Tier 1 + Tier 2)	$	35.07	6.9%	
4	PF Exchange (IOU)	$	58.73	-0.7%	
5	IP with 7(b)(3)	$	41.93	7.6%	
6	NR	$	73.83	-4.9%	
7					
8					

	A	B		C		D
9	**Annual Average $ (1000s)..........................**	BP-14		BP-16		**Change**
10	**Composite Rate Revenues..........................**	$	2,313,762	$	2,434,216	5.2%
11	**Non-Slice Rate Revenues...........................**	$	(259,448)	$	(263,920)	-1.7%
12	**Slice Rate Revenues..................................**	$	-	$	-	
13	**Load Shaping Rate Revenues.....................**	$	13,107	$	7,802	-40.5%
14	**Demand Rate Revenues ....**	$	43,171	$	48,354	12.0%
15	**Tier 1 Revenue Requirement.....................**	$	2,110,593	$	2,226,453	5.5%
16	**Tier 2 Revenue Requirement.....................**	$	15,636	$	25,187	
17	**Value of Slice Surplus...............................**	$	(120,207)	$	(119,982)	0.2%
18	**Lookback Return (credit)...........................**	$	(76,538)	$	(76,538)	
19	**Net Power Cost to All PF...........................**	$	1,929,483	$	2,055,120	6.5%
20	**Annual PF Load (w/firm Slice) (GWh)....**		61,158		60,789	-0.6%
21	**PF Average Net Cost ($/MWh).................**		31.55		33.81	7.2%
22	**Tier 1 Average Net Cost ($/MWh).............**		31.50		33.75	7.1%
23	**Tier 2 ($/MWh)...**		39.86		43.09	8.1%
24						
25	**Slice Sales..**	**BP-14**		**BP-16**		**Change**
26	**Composite+Slice...**	$	626,613	$	658,897	
27	**Tier 1 Average Cost ($/MWh)....................**		37.69		40.68	7.9%
28	**Value of Slice Surplus+Credits..................**	$	(140,935)	$	(140,699)	
29	**Net Cost of Slice Power..............................**	$	485,678	$	518,198	
30	**Tier 1 Average Net Cost ($/MWh).............**		29.21		31.99	9.5%
31						
32	**Non-Slice Sales...**	**BP-14**		**BP-16**		**Change**
33	**Composite+NonSlice+Shape+Demand......**	$	1,484,061	$	1,567,576	
34	**Tier 1 Average Cost ($/MWh)....................**		33.32		35.63	6.9%
35	**Credits..**	$	(55,810)	$	(55,820)	
36	**Net Cost of Non-Slice Power......................**	$	1,428,251	$	1,511,755	
37	**Tier 1 Average Net Cost ($/MWh).............**		32.07		34.37	7.2%
38						
39	**Tiered PF Rate Components......................**	**BP-14**		**BP-14**		**Change**
40	**Composite Rate ($/ pct/month)..................**	$	1,961,053	$	2,062,767	5.2%
41	**Non-Slice Rate ($/ pct/month)....................**	$	(301,568)	$	(306,652)	1.7%

Table 3: Revenues at Current Rates

	A	B	C	D	E	F	G	H	I	J
1	**Revenues at Current Rates**				**2015**		**2016**		**2017**	
2	**Category**				**$ (000's)**	**aMW**	**$ (000's)**	**aMW**	**$ (000's)**	**aMW**
3			Composite Revenue		$2,300,218	5,063	$2,307,887	6,848	$2,320,485	6,886
4			Non-Slice Revenue		($257,365)	-	($258,576)	-	($260,513)	-
5			Slice		$0	1,862	$0	-	$0	-
6			Load Shaping Revenue		($20,208)	19	$20,886	(9)	$30,346	22
7			Demand Revenue		$50,386	-	$45,681	-	$46,440	-
8			Irrigation Rate Discount		($18,816)	-	($20,604)	-	($20,604)	-
9			Low Density Discount		($33,691)	-	($38,300)	-	($38,924)	-
10			Tier 2		$26,439	75	$23,833	68	$27,679	79
11			RSS (Non-Federal)		$191	-	$1,329	-	$1,432	-
12		PF customers (CHWM) sub-total			$2,043,973	7,019	$2,082,137	6,908	$2,106,341	6,987
13		NR sub-total			($1,649)	-	$356	0	$356	0
14		DSIs sub-total			$77,366	312	$31,206	91	$31,110	91
15		Pre-Subscription (FPS) sub-total			$4,343	8	$2,920	8	$2,410	9
16		Short-term market sales sub-total			$358,943	1,153	$343,094	1,759	$362,109	1,703
17		Long Term Contractual Obligations sub-total			$30,626	108	$35,102	90	$35,102	90
18		Canadian Entitlement Return			$0	114	$0	119	$0	118
19		Renewable Energy Certificates sub-total			$1,107	-	$1,151	-	$648	-
20		Other Sales sub-total			($26,794)	-	$3,877	-	$0	-
21	**Gross Sales**				**$2,487,914**	**8,716**	**$2,499,487**	**8,975**	**$2,537,721**	**8,997**
22	**Miscellaneous Revenues**				**$29,917**	**178**	**$37,541**	**180**	**$29,580**	**180**
23	**Generation Inputs / Inter-business line**				**$132,908**	**9**	**$115,750**	**9**	**$115,750**	**9**
24		4(h)(10)(c)			$73,697	-	$91,107	-	$87,786	-
25		Colville and Spokane Settlements			$4,600	-	$4,600	-	$4,600	-
26	**Treasury Credits**				**$78,297**	-	**$95,707**	-	**$92,386**	-
27		Augmentation Power Purchase sub-total			$0	-	$0	-	$20,947	81
28		Balancing Power Purchase sub-total			$31,870	189	$14,631	121	$13,823	113
29		Other Power Purchase sub-total			$24,650	141	$30,769	60	$65,020	67

Table 4: Revenues at Proposed Rates

	A	B	C	D	E	F	G	H	I	J
1	**Revenues at Proposed Rates**				**2015**		**2016**		**2017**	
2	**Category**				**$ (000's)**	**aMW**	**$ (000's)**	**aMW**	**$ (000's)**	**aMW**
3			Composite Revenue		$2,300,218	5,063	$2,427,590	6,848	$2,440,841	6,886
4			Non-Slice Revenue		($257,365)	-	($262,935)	-	($264,905)	-
5			Slice		$0	1,862	$0	-	$0	-
6			Load Shaping Revenue		($20,208)	19	$4,040	(9)	$11,564	22
7			Demand Revenue		$50,386	-	$47,946	-	$48,763	-
8			Irrigation Rate Discount		($18,816)	-	($22,146)	-	($22,146)	-
9			Low Density Discount		($33,691)	-	($39,865)	-	($40,464)	-
10			Tier 2		$26,439	75	$22,866	68	$27,509	79
11			RSS (Non-Federal)		$191	-	$1,172	-	$1,679	-
12		PF customers (CHWM) sub-total			$2,043,973	7,019	$2,178,668	6,908	$2,202,841	6,987
13		NR sub-total			($1,649)	-	$356	0	$356	0
14		DSIs sub-total			$77,366	312	$33,509	91	$33,413	91
15		Pre-Subscription (FPS) sub-total			$4,343	8	$2,921	8	$2,411	9
16		Short-term market sales sub-total			$358,943	1,153	$343,094	1,762	$362,109	1,711
17		Long Term Contractual Obligations sub-total			$30,626	108	$35,102	90	$35,102	90
18		Canadian Entitlement Return			$0	114	$0	119	$0	118
19		Renewable Energy Certificates sub-total			$1,107	-	$1,151	-	$648	-
20		Other Sales sub-total			($26,794)	-	$3,877	-	$0	-
21	**Gross Sales**				**$2,487,914**	**8,716**	**$2,598,678**	**8,978**	**$2,636,880**	**9,006**
22	**Miscellaneous Revenues**				**$29,917**	**178**	**$37,541**	**180**	**$29,580**	**180**
23	**Generation Inputs / Inter-business line**				**$132,908**	**9**	**$115,750**	**9**	**$115,750**	**9**
24		4(h)(10)(c)			$73,697	-	$91,107	-	$87,786	-
25		Colville and Spokane Settlements			$4,600	-	$4,600	-	$4,600	-
26	**Treasury Credits**				**$78,297**	**-**	**$95,707**	**-**	**$92,386**	**-**
27		Augmentation Power Purchase sub-total			$0	-	$0	-	$20,947	81
28		Balancing Power Purchase sub-total			$31,870	189	$14,631	121	$13,823	113
29		Other Power Purchase sub-total			$24,650	141	$30,769	60	$65,020	67

Table 5:
Adjustments fo Financial Reserves Base Amount

	A	B	C	D	E	F
1	**Unit**	**Account**	**Stat Amt**	**Ref**	**Line Descr**	**Reason for adjustment**
2	POWER	999044	$ (673,094.63)	AR00114197	Receipt from DOJ	1
3	POWER	999044	$ (104,552.35)	AR00117261	Receipt from FERC	1
4	POWER	999044	$ (53,497.33)	AR00119524	Receipt from DOJ	1
5	POWER	999044	$ (2,789.38)	AR00122086	Receipt from DOJ	1
6	POWER	999044	$ (5.04)	AR00129431	Stock dividend	2
7	POWER	999044	$ (6,667.74)	AR00127956	Receipt from FERC	1
8	POWER	999044	$ (1,528.11)	AR00128358	Receipt from DOJ	1
9	POWER	999044	$ (1,080.25)	AR00143938	Receipt from DOJ	1
10	POWER	999044	$ (2,700.63)	AR00152218	Receipt from DOJ	1
11	POWER	999044	$ (43,791.87)	AR00153347	Receipt from FERC	1
12	POWER	999044	$ (5.04)	AR00144929	Stock dividend	2
13	POWER	999044	$ (5.04)	AR00147994	Stock dividend	2
14	POWER	999044	$ (5.04)	AR00151401	Stock dividend	2
15	POWER	999044	$ (5.04)	AR00156308	Stock dividend	2
16	POWER	999044	$ (5.04)	AR00158673	Stock dividend	2
17	POWER	999044	$ (73,765,314.86)		CAL ISO/PX Receipt	1
18						
19			**$ (74,655,047.39)**			
20						
21	**Reasons for adjustments**					
22	1) BPA’s receipt of payments for settlements or judgments pertaining to power marketing transactions that occurred before FY 2002,					
23	2) BPA’s receipt of funds as collections of outstanding receivables relating to revenues that occurred before FY 2002,					
24	3) BPA's payment for settlements or judgments pertaining to power marketing transactions that occurred before FY 2002.					
25						
26	Base amount of financial reserves =				**$ 495,600,000**	
27						
28	Adjustment to the base amount of financial reserves =				**$495,600,000 + $74,655,047**	
29						
30	**Resulting amount of financial reserves =**				**$ 570,255,047**	
31						
32	Adjustment amounts, if negative, are added to the base amount of financial reserves, thereby increasing the size of the base amount.					
33	Adjustment amounts, if positive, are subtracted from the base amount of financial reserves, thereby decreasing the size of the base amount.					

Table 6: Residential Exchange Benefits

	A	B	C	D
1	**Residential Exchange Benefits $(000s)**	**FY 2016**	**FY 2017**	
2	Avista Corporation	$ 1,254	$ 1,254	
3	Idaho Power Company	$ 10,201	$ 10,201	
4	NorthWestern Energy, LLC	$ 6,952	$ 6,952	
5	PacifiCorp	$ 64,972	$ 64,972	
6	Portland General Electric Company	$ 61,808	$ 61,808	
7	Puget Sound Energy, Inc.	$ 68,912	$ 68,912	
8	Net IOU Exchange	$ 214,100	$ 214,100	$ 214,100
9	Refund Amount	$ 76,538	$ 76,538	$ 76,538
10				
11	Clark Public Utilities	$ 2,623	$ 2,612	
12	Franklin	-	-	
13	Snohomish County PUD No. 1	$ 2,253	$ 2,291	
14	Net COU Exchange			$ 4,889
15	**Total Residential Exchange Benefits**			$ 295,527

Appendix A

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Appendix A

7(c)(2) Industrial Margin Study

1. INTRODUCTION

The purpose of this appendix is to describe BPA's calculation of the "typical margin" included by the Administrator's public body and cooperative customers in their retail industrial rates. The resulting margin is added to the PF-16 energy rates, which become the energy rates used in the IP-16 rate for BPA's direct-service industrial customers (DSIs).

Section 7(c)(1)(B) of the Northwest Power Act provides that rates applicable to BPA's DSI customers shall be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." Section 7(c)(2) provides that this determination shall be based on "the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates." This section further provides that the Administrator shall take into account:

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

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

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

2. METHODOLOGY

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

The Administrator's applicable wholesale rates to public body and cooperative customers are the PF-16 demand and energy rates before any 7(b)(2) or floor rate adjustments are applied.

2.2 "Typical Margin"

The typical margin is based generally on the overhead costs that consumer-owned utilities add to the cost of power in setting their retail industrial rates; see section 2.3 below.

2.3 Margin Determination Factors

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

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

In the past, BPA has accounted for "other service provisions" through a character of service adjustment for service to the first quartile of DSI load, which was interruptible as defined in the DSIs' power sales contract. Because the DSI contracts no longer include these provisions, this adjustment is not included in this study.

7(c)(2)(C) – Direct and Indirect Overhead Costs. Cost of service studies and other spreadsheets prepared by the public body and cooperative customers provide information to calculate the per-unit overhead costs associated with service to large industrial consumers.

3. APPLICATION OF THE METHODOLOGY

The derivation of the margin involves three steps. First, an individual margin is determined for each utility in the study. Second, each margin is weighted according to energy sales to derive an overall weighted average margin. Third, the BPA DSI delivery facilities charge is added to replace the distribution costs that otherwise may be included in the margin.

3.1 Data Base

The data base consists of cost of service information from 33 utilities that have at least one industrial consumer with a peak load of at least 3.5 MW. The data was collected in 2011 from qualifying utilities by the Public Power Council (PPC) under the terms of a confidentiality agreement. Under the terms of that agreement, the names of the individual utilities and their industrial consumers were deleted from the data base, and the names were not publicly disclosed. Furthermore, all parties wishing to evaluate the utility margin data at the PPC offices were required to sign confidentiality agreements. All utility data reported has been identified by a randomly assigned number. Attachment A displays each participating utility's individual data.

3.2 Utility Margins

The individual utility margins are based on costs allocated by the utilities to their industrial consumers. The categories of costs include production, transmission, distribution, taxes, and other overhead costs. Derivation of the margin involves three steps. First, an individual margin is determined for each utility in the study. Second, each margin is weighted according to energy sales to derive an overall weighted average margin. Third, the BPA DSI delivery facilities charge is added to replace the distribution costs that otherwise may be included in the margin.

3.3 Summary of Results

The final results of each step in the industrial margin calculation for each utility are shown on the summary table in Attachment A to this appendix. These results were used in the BP-12 rate case. As shown on the summary table, the weighted industrial margin for the BP-12 rate case was 0.685 mills/kWh.

4. THE INDUSTRIAL MARGIN FOR THE BP-16 RATE CASE

BPA did not conduct a new industrial margin survey for the BP-16 rate case. Instead, the industrial margin is escalated for inflation between the start of the BP-12 rate period and the start of the BP-16 rate period. The escalation factor uses the GDP Implicit Price Deflator using actuals from the Bureau of Economic Analysis and forecast from Global Insight. Accordingly, the BP-12 industrial margin, 0.685 mills/kWh, is multiplied by 1.07. The BP-16 industrial margin is 0.733 mills/kWh.

Attachment A

Summary - 2012 Margin Study Results

Utility Code Number	Test Period Energy (KWh)	Total Cost	Production	Transmission	Distribution	Other	Taxes	Weighted Margin
1	51,410,428					$ 5.67		0.017
2	1,581,923,558					$ 0.04		0.004
3	95,688,000	$ 47.66	$ 36.62	$ -	$ 9.38	$ 0.45	$ 1.21	0.002
5	42,823,202	$ 57.46	$ 36.78	$ 0.85	$ 18.61	$ 0.42	$ 0.80	0.001
6	29,114,880	$ 43.02	$ 34.50	$ 2.36	$ 2.87	$ 0.72	$ 2.57	0.001
7	40,694,000					$ -		0.000
8	405,668,000					$ -		0.000
9	361,407,000	$ 4.78	$ 3.84	$ 0.01	$ 0.72	$ 0.07	$ 0.13	0.002
11	467,121,000	$ 45.11	$ 32.63	$ 5.45	$ 3.18	$ 0.81	$ 3.04	0.022
12	248,035,470	$ 36.22	$ 34.20	$ 0.25	$ 1.36	$ 0.00	$ 0.38	0.000
13	119,932,734	$ 38.94	$ 36.80	$ -	$ 0.04	$ 0.01	$ 2.09	0.000
14	61,910,899	$ 10.77	$ -	$ 0.47	$ 9.79	$ 0.51	$ -	0.002
15	966,012,620					$ 0.02		0.001
16	169,040,000					$ 0.47		0.005
17	352,800,436	$ 41.45	$ 30.46	$ 0.23	$ 10.69	$ 0.06	$ -	0.001
18	5,390,158,000	$ 49.42	$ 40.45	$ 0.90	$ 6.60	$ 0.88	$ 0.58	0.273
20	297,405,000					$ 0.15		0.003
21	340,000,000					$ 0.43		0.008
23	78,758,000	$ 43.69	$ 33.49	$ 0.12	$ 8.23	$ 1.11	$ 0.74	0.005
24	203,423,478	$ 62.26	$ 33.19	$ 4.05	$ 22.70	$ 0.10	$ 2.22	0.001
25	152,608,000	$ 40.67	$ 31.32	$ 0.77	$ 4.29	$ 3.40	$ 0.89	0.030
26	47,700,000	$ 46.82	$ 34.17	$ 0.85	$ 10.86	$ 0.32	$ 0.62	0.001
27	15,897,484					$ 0.32		0.000
28	3,022,602,000					$ 0.54		0.093
29	718,303,000					$ 0.35		0.015
30	808,561,000	$ 51.24	$ 47.77	$ 0.14	$ 0.30	$ 0.04	$ 2.99	0.002
31	223,878,000	$ 36.86	$ 29.79	$ -	$ 5.86	$ 0.71	$ 0.49	0.009
32	750,395,000	$ 54.12	$ 44.55	$ 2.13	$ 0.15	$ 4.19	$ 3.10	0.180
33	194,837,000	$ 46.71	$ 39.37	$ -	$ 4.53	$ 0.01	$ 2.81	0.000
34	21,884,198					$ 5.29		0.007
35	94,165,000	$ 26.69	$ 7.06	$ 0.66	$ 15.48	$ 0.03	$ 3.47	0.000
36	19,516,800					$ 0.03		0.000
37	38,909,777					$ 0.01		0.000
Total:	17,412,583,964							0.685

Utility Number: # 1

Two industrial customers; rates set through contract.

Customer 1: BPA rate plus $1.09/MWh; 2009 sales (kWh)	=		**31,485,920**
Margin	=		**$ 34,320**
Customer 2: BPA rate plus $21,430/mo; 2009 sales	=		**19,924,508**
Margin	=		**$ 257,160**
Total margin from Customers 1 & 2	=	**$ 291,480**	
Sales to Customers 1 & 2 (kWh)	=	**51,410,428**	

Utility Number: # 2

Large Industrial includes sales under Schedules 14, 15, & 16

	Ave # of customers	Load (kWh)	Monthly basic charge
Schedule 14	3	123,852,000	$ 200
Schedule 15	6	1,223,870,998	$ 500
Schedule 16	10	234,200,560	$ 200
		1,581,923,558	
		Total basic charges/year =	**$ 67,200**

Utility Number: # 3							
	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ 3,503,816	$ 3,503,816					$ 3,503,816
Transmission:	$ -						
Distribution:	$ 66,980			$ 66,980			$ 66,980
Customer Accounts:	$ 20,315				$ 20,315		$ 20,315
Customer Services:	$ 4,599				$ 4,599		$ 4,599
Admin & Genl:	$ 68,093			$ 49,632	$ 18,461		$ 68,093
Taxes:	$ 115,384					$ 115,384	$ 115,384
Depreciation:	$ 779,001			$ 779,001			$ 779,001
Interest:	$ 2,352			$ 2,352			$ 2,352
TOTAL	$ 4,560,540	$ 3,503,816		$ 897,965	$ 43,375	$ 115,384	$ 4,560,540

Utility Number: # 5							
	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ 1,574,999	$ 1,574,999					$ 1,574,999
Transmission:	$ 14,196		$ 14,196				$ 14,196
Distribution:	$ 310,053			$ 310,053			$ 310,053
Customer Accounts:	$ 7,316				$ 7,316		$ 7,316
Meter Reading:	$ 194			$ 194.00			$ 194
Customer Service:	$ 3,456				$ 3,456		$ 3,456
Sales Exp:	$ 2,549				$ 2,549		$ 2,549
Admin & Genl (1):	$ 120,230		$ 5,056	$ 110,429	$ 4,744		$ 120,230
Depreciation:	$ 232,235		$ 10,168	$ 222,067			$ 232,235
Taxes:	$ 34,108					$ 34,108	$ 34,108
Interest:	$ 159,676		$ 6,991	$ 152,685			$ 159,676
Other:	$ 1,731		$ 76	$ 1,655			$ 1,731
TOTAL	$ 2,460,743	$ 1,574,999	$ 36,486	$ 797,084	$ 18,065	$ 34,108	$ 2,460,743

Utility Number: # 6

	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	$ 1,035,622	$ 1,035,622					$ 1,035,622
Transmission:	$ 712		$ 712	$ -			$ 712
Distribution:	$ 59,107			$ 59,107			$ 59,107
Meter Reading:	$ 18			$ 18			$ 18
Customer Records & Collection:	$ 54			$ 54			$ 54
Misc Customer Service:	$ 87				$ 87		$ 87
A & G:	$ 41,855		$ 497	$ 41,297	$ 61		$ 41,855
Taxes:	$ 74,851					$ 74,851	$ 74,851
Inrerest:	$ 46,721		$ 555	$ 46,166			$ 46,721
Capital Projects:	$ 88,598		$ 67,619		$ 20,979		$ 88,598
Other Deduction (2):	$ (63,872)		$ (758)	$ (63,021)	$ (93)		$ (63,872)
BPA Conservation, Con Aug, other:	$ (31,231)	$ (31,231)					$ (31,231)
TOTAL	$ 1,252,522	$ 1,004,391	$ 68,625	$ 83,621	$ 21,034	$ 74,851	$ 1,252,522

Utility Number: # 7
One industrial customer with a monthly peak of at least 3.5 MW; 2009 load = 40,694 MWh
Monthly Base Charge = $0.00
Demand Charge = $5.75/kW
Energy Charge = $0.0316/kWh

Utility Number: # 8
One industrial customer with a monthly peak of at least 3.5 MW; 2009 load = 405,668 MWh
Monthly Base Charge = $0.00
Industrial rates set by city ordinance

Utility Number: # 9

	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Power Costs:	$ 1,387,888	$ 1,387,888					$ 1,387,888
Transmission:	$ 1,320		$ 1,320				$ 1,320
Distribution:	$ 71,299			$ 71,299			$ 71,299
Customer Accounts:	$ 263				$ 263		$ 263
Public Relations & Info:	$ 11,873				$ 11,873		$ 11,873
Energy Services:	$ 3,159				$ 3,159		$ 3,159
Admin & Genl:	$ 63,036		$ 946	$ 51,079	$ 11,011		$ 63,036
Depreciation:	$ 75,872		$ 1,379	$ 74,493			$ 75,872
Taxes:	$ 48,396					$ 48,396	$ 48,396
Interest:	$ 65,238		$ 1,186	$ 64,052			$ 65,238
TOTAL	$ 1,728,344	$ 1,387,888	$ 4,831	$ 260,923	$ 26,306	$ 48,396	$ 1,728,344

Utility Number: # 11	Two Industrial Customers	Production	Transmission	Distribution	Other	Taxes	Sum
Power:	$ 15,244,327	$ 15,244,327					$ 15,244,327
Transmission:	$ 2,544,405		$ 2,544,405				$ 2,544,405
Distribution:	$ 1,481,945			$ 1,481,945			$ 1,481,945
Meter Reading + Cust Records:	$ 5,366			$ 5,366			$ 5,366
Customer Education:	$ 77,324				$ 77,324		$ 77,324
Low Income Assist.:	$ 156,540				$ 156,540		$ 156,540
Electirc Marketing:	$ 142,594				$ 142,594		$ 142,594
Taxes:	$ 1,419,465					$ 1,419,465	$ 1,419,465
TOTAL	$ 21,071,966	$ 15,244,327	$ 2,544,405	$ 1,487,311	$ 376,458	$ 1,419,465	$ 21,071,966

Utility Number: # 12							
	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Generation:	$ 644,417	$ 644,417					$ 644,417
Purchased Power:	$ 8,379,469	$ 8,379,469					$ 8,379,469
Transmission:	$ 77,781		$ 77,781				$ 77,781
Distribution:	$ 412,110			$ 412,110			$ 412,110
Meter Reading + Customer Records:	$ 9,303			$ 9,303			$ 9,303
Customer Service:	$ 3,113				$ 3,113		$ 3,113
Admin & Genl:	$ 496,109	$ 278,795	$ 33,651	$ 182,317	$ 1,347		$ 496,109
Taxes:	$ 95,106					$ 95,106	$ 95,106
Interest:	$ 341,788	$ 192,595	$ 23,246	$ 125,947			$ 341,788
Capital Projects:	$ 455,818	$ 256,850	$ 31,002	$ 167,966			$ 455,818
Other Revenue:	$ (1,931,751)	$ (1,270,440)	$ (103,488)	$ (560,694)	$ (4,142)		$ (1,938,764)
TOTAL	$ 8,983,263	$ 8,481,687	$ 62,191	$ 336,948	$ 318	$ 95,106	$ 8,976,250

Utility Number: # 13

	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	$ 3,813,592	$ 3,813,592					$ 3,813,592
Transmission							
Distribution							
Conservation	$ 600,000	$ 600,000					$ 600,000
Meters & Services	$ 4,742			$ 4,742			$ 4,742
Accounting	$ 536				$ 536		$ 536
Customer Related	$ 789				$ 789		$ 789
Revenue Related	$ 250,374					$ 250,374	$ 250,374
TOTAL	$ 4,670,033	$ 4,413,592		$ 4,742	$ 1,325	$ 250,374	$ 4,670,033

Utility Number # 14							
	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ -						
Transmission:	$ 29,120		$ 29,120				$ 29,120
Distribution:	$ 560,614			$ 560,614			$ 560,614
Metering & Billing:	$ 45,398			$ 45,398			$ 45,398
Customer Services:	$ 31,565				$ 31,565		$ 31,565
TOTAL	$ 666,697		$ 29,120	$ 606,012	$ 31,565		$ 666,697

Utility Number: # 15

7 customers in High Voltage General rate class; load = 966,012,620 kWh

Customer Charge per meter per month =	**$ 210**
Total customer charges per year =	**$ 17,640**

Utility Number: # 16

1 large industrial customer with peak of at least 3.5 aMW

Total Insustrial sales in 2009 = 169,040 MWh

Fixed charge (equivalent to customer charge of $6,557/month; annual cost =	$	78,684

Utility Number: # 17	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	$ 10,747,941	$ 10,747,941					$ 10,747,941
Transmission:	$ 15,940		$ 15,940				$ 15,940
Distribution:	$ 735,733			$ 735,733			$ 735,733
Customer Accnts:	$ 4,917				$ 4,917		$ 4,917
Customer Svcs:	$ 1,963				$ 1,963		$ 1,963
Interest on Debt (2):	$ 398,427		$ 8,449	$ 389,978			$ 398,427
Depreciation (2):	$ 551,528		$ 11,696	$ 539,832			$ 551,528
Additional revenue req.:	$ 2,165,398		$ 45,621	$ 2,105,704	$ 14,073		$ 2,165,398
TOTAL	$ 14,621,847	$ 10,747,941	$ 81,706	$ 3,771,247	$ 20,953		$ 14,621,847

Utility Number: # 18							
	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Generation:	$ 45,179,704	$ 45,179,704					$ 45,179,704
Purchased Power:	$ 182,460,007	$ 182,460,007					$ 182,460,007
Conservation:	$ 26,968,662	$ 26,968,662					$ 26,968,662
Transmission:	$ 9,881,306		$ 9,881,306				$ 9,881,306
Distribution:	$ 72,213,558			$ 72,213,558			$ 72,213,558
Customer costs:	$ 4,980,734				$ 4,980,734		$ 4,980,734
Low income assistance:	$ 4,680,598				$ 4,680,598		$ 4,680,598
Franchise Adjustments:	$ 3,136,376					$ 3,136,376	$ 3,136,376
Revenue Credits:	$ (83,124,365)	$ (36,590,117)	$ (5,011,314)	$ (36,623,179)	$ (4,899,754)		$ (83,124,365)
TOTAL	$ 266,376,580	$ 218,018,256	$ 4,869,992	$ 35,590,379	$ 4,761,578	$ 3,136,376	$ 266,376,580

Utility Number: # 20

2 large industrial customers with peak of at least 3.5 aMW

Total Industrial sales in 2009 = 297,405 MWh

Margin charges = 0.0195 cents/kWh for first 19.1 aMW in a month, and 0.0098 cents for each kWh thereafter

167,316,000	kWh at 0.0195 cents
130,089,000	kWh at 0.0098 cents

Total margin charges for 2009 = **4,537,534** cents = **$ 45,375**

Utility Number: # 21

Industrial sales in 2010 = 340,000 MWh

Industrial customers in 2010 = 35

Customer cost per month in 2010 = **$349**

Total customer cost = **$146,639**

Utility Number: # 23							
	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	$ 2,626,334	$ 2,626,334					$ 2,626,334
Transmission:							
Distribution:	$ 318,070			$ 318,070			$ 318,070
Customer Services & Accts:	$ 63,752			$ 9,575	$ 54,177		$ 63,752
A & G:	$ 155,355	$ 11,293		$ 130,111	$ 13,951		$ 155,355
Depreciation:	$ 141,272		$ 9,761	$ 112,513	$ 18,998		$ 141,272
Interest:	$ 77,847			$ 77,847			$ 77,847
Taxes:	$ 58,569					$ 58,569	$ 58,569
TOTAL	$3,441,199	$2,637,627	$9,761	$648,116	$87,126	$58,569	$3,441,199

Utility Number: # 24

	(includes NLSL)	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ 6,752,558	$ 6,752,558					$ 6,752,558
Transmission:	$ 414,702		$ 414,702				$ 414,702
Distribution:	$ 2,326,532			$ 2,326,532			$ 2,326,532
Customer Related:	$ 19,242				$ 19,242		$ 19,242
A & G:	$ 448,614		$ 67,395	$ 378,092	$ 3,127		$ 448,614
Depr & Amort:	$ 939,205		$ 142,086	$ 797,119			$ 939,205
Taxes:	$ 451,195					$ 451,195	$ 451,195
Interest:	$ 1,347,794		$ 203,898	$ 1,143,896			$ 1,347,794
Capital Requirements:	$ 232,129		$ 35,117	$ 197,011			$ 232,129
Other Income:	$ (267,290)		$ (40,154)	$ (225,272)	$ (1,863)		$ (267,290)
TOTAL	$ 12,664,681	$ 6,752,558	$ 823,043	$ 4,617,379	$ 20,506	$ 451,195	$ 12,664,681

Utility Number: # 25	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	$ 4,780,364	$ 4,780,364					$ 4,780,364
Transmission:	$ 69,374		$ 69,374				$ 69,374
Distribution:	$ 393,197			$ 393,197			$ 393,197
Customer Related:	$ 1,729				$ 1,729		$ 1,729
A & G:							
Prop ins/inj & damag:	$ 17,112			$ 17,112			$ 17,112
Cust acct/serv & info/sales rel:	$ 480,913				$ 480,913		$ 480,913
Depreciation:	$ 328,871	$ 18	$ 48,211	$ 244,836	$ 35,806		$ 328,871
Taxes:	$ 135,572					$ 135,572	$ 135,572
TOTAL	$ 6,207,132	$ 4,780,382	$ 117,585	$ 655,145	$ 518,448	$ 135,572	$ 6,207,132

Utility Number: # 26	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	$ 1,629,832	$ 1,629,832					$ 1,629,832
Transmission:	$ 12,295		$ 12,295				$ 12,295
Distribution:	$ 150,666			$ 150,666			$ 150,666
Customer Related:							
Meter reading & cust. Records:	$ 6,440			$ 6,440			$ 6,440
Customer sales & service:	$ 7,343				$ 7,343		$ 7,343
Depreciation:	$ 129,443		$ 9,395	$ 120,048			$ 129,443
A & G + Other Expense:	$ 185,637		$ 12,914	$ 165,011	$ 7,712		$ 185,637
Taxes:	$ 29,545					$ 29,545	$ 29,545
Interest:	$ 74,929		$ 5,438	$ 69,491			$ 74,929
Other Expenses:	$ 7,009		$ 506	$ 6,200	$ 302		$ 7,008
TOTAL	$2,233,139	$1,629,832	$40,548	$517,856	$15,357	$29,545	$2,233,138

Utility Number: # 27

Utility # 27 has 1 large industrial customer; 2009 load = **15,897,484** kWh

Customer cost per month in 2010 = **$ 418.70**

Total customer cost = $ 5,024.40

Utility Number: # 28

Utility # 28 has 3 large industrial customers; 2009 load = 3,022,602,000 kWh
Margin charges set in contract with each customer; total margin charges in 2009 = $1,619,690

Utility Number: # 29

1 large industrial customer; 2009 load = 718,303 MWh			
Direct costs of contract administration for this customer (2 plants)	=	$	175,442
		$	79,376
		$	**254,818**

Utility Number: # 30

	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ 42,669,341	$ 42,669,341					$ 42,669,341
Transmission:	$ -		$ -				$ -
Distribution:	$ 322,009			$ 322,009			$ 322,009
Meter reading + customer records:	$ 2,429			$ 2,429			$ 2,429
Customer related:	$ 1,301				$ 1,301		$ 1,301
A & G:	$ 260,302			$ 259,262	$ 1,040		$ 260,302
Taxes:	$ 2,418,041					$ 2,418,041	$ 2,418,041
Interest:	$ 673,382			$ 673,382			$ 673,382
Capital Projects:	$ 290,096		$ 110,346	$ 145,596	$ 34,154		$ 290,096
Other Revenues:	$ (5,209,277)	$ (4,047,303)		$ (1,157,333)	$ (4,641)		$ (5,209,277)
TOTAL	$ 41,427,624	$ 38,622,038	$ 110,346	$ 245,345	$ 31,854	$ 2,418,041	$ 41,427,624

Utility Number: # 31	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production	$ 6,669,764	$ 6,669,764					$ 6,669,764
Transmission							
Fixed Oper Costs (Distn)	$ 406,590			$ 406,590			$ 406,590
on Oper Exp (Cust Svc & Acct)	$ 71,114				$ 71,114		$ 71,114
Admin & Bus Exp	$ 530,588			$ 442,017	$ 88,571		$ 530,588
Taxes	$ 110,812					$ 110,812	$ 110,812
LTGO Debt Servd & Cap	$ 462,840			$ 462,840			$ 462,840
TOTAL	$ 8,251,708	$ 6,669,764	$ -	$ 1,311,447	$ 159,685	$ 110,812	$ 8,251,708

Utility Number: # 32	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ 33,760,238	$ 33,760,238					$ 33,760,238
Transmission:	$ 145,001		$ 145,001				$ 145,001
Distribution:	$ 10,066			$ 10,066			$ 10,066
Customer Services & Accounts:	$ 2,171,387				$ 2,171,387		$ 2,171,387
A & G:	$ 989,157		$ 61,651	$ 4,280	$ 923,226		$ 989,157
Capital Projects:	$ 1,151,312		$ 1,076,576	$ 74,736			$ 1,151,312
Debt Service:	$ 333,697		$ 312,035	$ 21,662			$ 333,697
Direct Assignments:	$ 1,442,631		$ 89,915	$ 6,242	$ 1,346,474		$ 1,442,631
Other Revenue:	$ (1,721,861)	$ (329,663)	$ (86,749)	$ (6,022)	$ (1,299,426)		$ (1,721,860)
Taxes:	$ 2,329,920					$ 2,329,920	$ 2,329,920
TOTAL	$ 40,611,548	$ 33,430,575	$ 1,598,429	$ 110,963	$ 3,141,661	$ 2,329,920	$ 40,611,549

Utility Number: # 33

	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Power:	$ 7,378,831	$ 7,378,831					$ 7,378,831
Conservation:	$ 134,032	$ 134,032					$ 134,032
Distribution:	$ 161,203			$ 161,203			$ 161,203
Customer Related:	$ 714				$ 714		$ 714
A & G:	$ 398,772	$ 180,599		$ 217,211	$ 962		$ 398,772
Broad Band:	$ 93,962	$ 42,554		$ 51,181	$ 227		$ 93,962
Interest:	$ 531,746			$ 531,746			$ 531,746
Cash Flow:	$ 495,596	$ 224,450		$ 269,950	$ 1,196		$ 495,596
Taxes:	$ 547,357					$ 547,357	$ 547,357
Other Revenue:	$ (640,934)	$ (290,272)		$ (349,116)	$ (1,546)		$ (640,934)
TOTAL	$ 9,101,279	$ 7,670,195	$ -	$ 882,175	$ 1,552	$ 547,357	$ 9,101,279

Utility Number: # 34

1 large industrial customer with peak of at least 3.5 aMW

2008 Industrial load = 21,884,198 kWh

Margin = $.00529/kWh

Total margin charges for 2008 = **$ 115,767**

Utility Number: # 35

	Total Utility	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Power Production:	$ 2,477,820	$ 318,447	$ 318,447					$ 318,447
Transmission:	$ 428,864	$ 55,117		$ 55,117				$ 55,117
Distribution:	$ 4,226,132	$ 543,138			$ 543,138			$ 543,138
Metering Reading:	$ 571,769	$ 73,483			$ 73,483			$ 73,483
Credit & Billing:	$ 853,653	$ 109,711			$ 109,711			$ 109,711
Information & Advertising:	$ 52,530	$ 6,751				$ 6,751		$ 6,751
Administrative & General Expenses:	$ 4,598,604	$ 591,008	$ 170,068	$ 29,435	$ 387,900	$ 3,605		$ 591,008
Taxes:	$ 2,541,360	$ 326,613					$ 326,613	$ 326,613
Debt Service:	$ 7,940,000	$ 1,020,441	$ 295,443	$ 51,135	$ 673,863			$ 1,020,441
Capital Projects:	$ 6,280,000	$ 807,100	$ 233,675	$ 40,445	$ 532,980			$ 807,100
Total Transfers:	$ 841,720	$ 108,177	$ 31,320	$ 5,421	$ 71,436			$ 108,177
Energy Sales:	$ (9,248,760)	$ (1,188,642)	$ (342,042)	$ (59,201)	$ (780,148)	$ (7,251)		$ (1,188,642)
Other Revenues:	$ (2,006,586)	$ (257,885)	$ (41,976)	$ (60,458)	$ (155,087)	$ (363)		$ (257,884)
TOTAL	$ 19,557,106	$ 2,513,460	$ 664,935	$ 61,895	$ 1,457,276	$ 2,742	$ 326,613	$ 2,513,461

Utility Number: # 36

1 large industrial customer; 2008 load = 19,516,800 kWh

Monthly Customer Charge = **$51.37**   Total charges = **$ 616.44**

Utility Number: # 37

1 large industrial customer; 2010 load = 38,909,777 kWh

Customer charge = **$208**