## 2012 BPA Final Rate Proposal

# Power Rates Study

July 2011

BP-12-FS-BPA-01

**POWER RATES STUDY**

**TABLE OF CONTENTS**

**TABLES**

## COMMONLY USED ACRONYMS

| | |
|---|---|
| AGC | Automatic Generation Control |
| ALF | Agency Load Forecast (computer model) |
| aMW | average megawatt(s) |
| AMNR | Accumulated Modified Net Revenues |
| ANR | Accumulated Net Revenues |
| ASC | Average System Cost |
| BiOp | Biological Opinion |
| BPA | Bonneville Power Administration |
| Btu | British thermal unit |
| CDD | cooling degree day(s) |
| CDQ | Contract Demand Quantity |
| CGS | Columbia Generating Station |
| CHWM | Contract High Water Mark |
| Commission | Federal Energy Regulatory Commission |
| COSA | Cost of Service Analysis |
| COU | consumer-owned utility |
| Corps or USACE | U.S. Army Corps of Engineers |
| Council | Northwest Power and Conservation Council |
| 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 |
| DOE | Department of Energy |
| DSI | direct-service industrial customer or direct-service industry |
| DSO | Dispatcher Standing Order |
| EIA | Energy Information Administration |
| EIS | Environmental Impact Statement |
| EN | Energy Northwest, Inc. |
| EPP | Environmentally Preferred Power |
| ESA | Endangered Species Act |
| 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 Products and Services (rate) |
| FY | fiscal year (October through September) |
| GARD | Generation and Reserves Dispatch (computer model) |

| | |
|---|---|
| GEP | Green Energy Premium |
| GRSPs | General Rate Schedule Provisions |
| GTA | General Transfer Agreement |
| GWh | gigawatthour |
| HDD | heating degree day(s) |
| HLH | Heavy Load Hour(s) |
| HOSS | Hourly Operating and Scheduling Simulator (computer model) |
| HYDSIM | Hydro Simulation (computer model) |
| ICE | IntercontinentalExchange |
| *inc* | increase, increment, or incremental |
| IOU | investor-owned utility |
| IP | Industrial Firm Power (rate) |
| IPR | Integrated Program Review |
| IRD | Irrigation Rate Discount |
| JOE | Joint Operating Entity |
| kW | kilowatt (1000 watts) |
| kWh | kilowatthour |
| LDD | Low Density Discount |
| LLH | Light Load Hour(s) |
| LRA | Load Reduction Agreement |
| Maf | million acre-feet |
| Mid-C | Mid-Columbia |
| MMBtu | million British thermal units |
| MNR | Modified Net Revenues |
| MRNR | Minimum Required Net Revenue |
| MW | megawatt (1 million watts) |
| MWh | megawatthour |
| NEPA | National Environmental Policy Act |
| NERC | North American Electric Reliability Corporation |
| NFB | National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) |
| 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 |
| NPV | net present value |
| NR | New Resource Firm Power (rate) |
| NT | Network Transmission |
| NTSA | Non-Treaty Storage Agreement |
| NUG | non-utility generation |
| NWPP | Northwest Power Pool |
| OATT | Open Access Transmission Tariff |
| O&M | operation and maintenance |

| | |
|---|---|
| OMB | Office of Management and Budget |
| OY | operating year (August through July) |
| PF | Priority Firm Power (rate) |
| PFp | Priority Firm Public (rate) |
| PFx | Priority Firm Exchange (rate) |
| PNCA | Pacific Northwest Coordination Agreement |
| PNRR | Planned Net Revenues for Risk |
| PNW | Pacific Northwest |
| POD | Point of Delivery |
| POI | Point of Integration or Point of Interconnection |
| POM | Point of Metering |
| POR | Point of Receipt |
| Project Act | Bonneville Project Act |
| PRS | Power Rates Study |
| PS | BPA Power Services |
| PSW | Pacific Southwest |
| PTP | Point to Point Transmission (rate) |
| PUD | public or people’s utility district |
| RAM | Rate Analysis Model (computer model) |
| RAS | Remedial Action Scheme |
| RD | Regional Dialogue |
| REC | Renewable Energy Certificate |
| Reclamation or USBR | U.S. Bureau of Reclamation |
| REP | Residential Exchange Program |
| RevSim | Revenue Simulation Model (component of RiskMod) |
| RFA | Revenue Forecast Application (database) |
| RHWM | Rate Period High Water Mark |
| RiskMod | Risk Analysis Model (computer model) |
| RiskSim | Risk Simulation Model (component of RiskMod) |
| ROD | Record of Decision |
| RPSA | Residential Purchase and Sale Agreement |
| RR | Resource Replacement (rate) |
| RSS | Resource Support Services |
| RT1SC | RHWM Tier 1 System Capability |
| RTO | Regional Transmission Operator |
| SCADA | Supervisory Control and Data Acquisition |
| SCS | Secondary Crediting Service |
| Slice | Slice of the System (product) |
| T1SFCO | Tier 1 System Firm Critical Output |
| TCMS | Transmission Curtailment Management Service |
| TOCA | Tier 1 Cost Allocator |
| TPP | Treasury Payment Probability |
| Transmission System Act | Federal Columbia River Transmission System Act |
| TRL | Total Retail Load |
| TRM | Tiered Rate Methodology |
| TS | BPA Transmission Services |

| | |
|---|---|
| TSS | Transmission Scheduling Service |
| UAI | Unauthorized Increase |
| ULS | Unanticipated Load Service |
| USACE or Corps | U.S. Army Corps of Engineers |
| USBR or Reclamation | U.S. Bureau of Reclamation |
| USFWS | U.S. Fish and Wildlife Service |
| VERBS | Variable Energy Resources Balancing Service (rate) |
| VOR | Value of Reserves |
| WECC | Western Electricity Coordinating Council (formerly WSCC) |
| WIT | Wind Integration Team |
| WSPP | Western Systems Power Pool |

# 1. INTRODUCTION AND BACKGROUND

## 1.1 Power Rates Study Overview

The Power Rates Study (Study) explains the processes and calculations used to develop the power rates and billing determinants for BPA's wholesale power products and services. The Study 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 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 rate design process is illustrated in section 1 of the Power Rates Study Documentation (Documentation), BP-12-FS-BPA-01A, and described further throughout this Study.

The development of rates in the Study uses inputs from a variety of sources. Loads and resources are provided to the Study by the Power Loads and Resources Study, BP-12-FS-BPA-03, and its accompanying documentation, BP-12-FS-BPA-03A. Power revenue requirement information is provided by the Power Revenue Requirement Study, BP-12-FS-BPA-02, and its accompanying documentation, BP-12-FS-BPA-02A. The Power Risk and Market Price Study, BP-12-FS-BPA-04, and its accompanying documentation, BP-12-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. These 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. The results of the Generation Inputs Study, BP-12-FS-BPA-05, are provided to the Study as revenue credits. Explanation and documentation for these credits arising from generation inputs and other inter-business line cost allocations are included in the Generation Inputs Study.

The results of the power rate development process, including rates for power products and services, plus general rate schedule provisions, appear in the Power Rate Schedules, BP-12-A-02B. 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 in recovering expenses and supplying adequate cash to cover non-expense cash outlays. Power Revenue Requirement Study, BP-12-FS-BPA-02, section 3.3.

## 1.2 Statutory and Legal Overview

The Northwest Power Act, 16 U.S.C. § 839, is the most prominent 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. Such rates shall be established in accordance with sections 9 and 10 of the Federal Columbia River Transmission System Act (16 U.S.C. § 838) [16 U.S.C. §§ 838g and 838h], section 5 of the Flood Control Act of 1944 [16 U.S.C. § 825s], and the provisions of this chapter.

Section 7(a)(1) directs the Administrator to 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. The Northwest Power Act defines "periodically review and revise" as not less frequently than once in every five years. The section also directs that rates recover all of the Administrator's costs, including the repayment of the Federal investment in the Federal Columbia River Power System. Rates are also to be in accord with two other statutes, the Transmission System Act and the Flood Control Act.

Section 7 directs the allocation of costs, which is performed in a cost of service analysis (see section 2.1 of this Study), and a set of rate directives providing further guidance on how individual rates are to be derived (see section 2.2).

### 1.2.1 Cost of Service Analysis

Northwest Power Act sections 7(b)(1), 7(d), 7(f), and 7(g) provide guidance to BPA for allocating resource and other costs to load (rate) pools. That guidance is summarized below. See section 2.1 for a full discussion of the implementation of these sections of the Northwest Power Act in the Rate Analysis Model (RAM2012).

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) 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 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) instructs that Federal base system (FBS) resources are used to serve the PF rate pool until 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. The allocation of these costs is discussed throughout section 2.1.

Section 7(d)(1) states:

> In order to avoid adverse impacts on retail rates of the Administrator's customers with low system densities, the Administrator shall, to the extent appropriate, apply discounts to the rate or rates for such customers.

Section 7(d)(1) instructs BPA to apply a Low Density Discount (LDD) to mitigate the costs of customers with relatively fewer customers spread over relatively larger geographic areas. The LDD is discussed in sections 2.1.3.3 and 4.1.1.4.

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 what and 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 remaining load (power sold at the New Resources Firm Power (NR) rate and the Firm Power Products and Services (FPS) rate). The allocation of these costs is discussed throughout section 2.1.

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) 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. The allocation of these costs is discussed throughout section 2.1.

### 1.2.2 Rate Directives

Northwest Power Act sections 7(c), 7(b)(2), and 7(b)(3) provide further guidance to BPA for ratesetting. Section 2.2 discusses these rate adjustments in detail.

Section 7(c) in pertinent part states:

> The rate or rates applicable to direct service industrial customers shall be established for the period beginning July 1, 1985, 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) describes how BPA is to set the rate it charges DSI customers. It provides that the DSI rate will be set to be equitable in relation to retail industrial rates of consumer-owned utility (COU) customers. Section 7(c) provides guidance on how to establish and modify this equitable relationship.

> The [DSI rate] shall be based upon 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 but shall take into account the comparative size and character of the loads served, the relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions, and direct and indirect overhead costs, all as related to the delivery of power to industrial customers, except that

> the Administrator's rates during such period shall in no event be less than the rates in effect for the contract year ending on June 30, 1985.

Section 7(c) speaks of the "applicable wholesale rates" to COU customers plus the "typical margins" included by those customers in their retail industrial rates. These parts of the DSI rate are discussed in section 2.2.2 and Appendix A. The section also provides for a comparison of the proposed DSI rate to the DSI rate in effect in 1985, known as the floor rate test. The floor rate test is discussed in section 2.2.2.4. Finally, section 7(c)(3) provides:

> The Administrator shall adjust such rates to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers.

Section 7(c)(3) directs 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 typically made through a Value of Reserves (VOR) credit. The VOR analysis is discussed in section 3.3.1.1.

In summary, the result of section 7(c) is that the DSI rate is set equal to the applicable wholesale rate, plus the typical margin, minus the VOR credit, subject to the DSI floor rate test. Because the DSI rate interacts with the PF rate and the NR rate, the three rates are determined simultaneously through a solution called the 7(c)(2) Delta. The determination and application of the 7(c)(2) Delta is discussed in section 2.2.2.3.

Section 7(b)(2) states:

> After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency

> customers, exclusive of amounts charged such customers under subsection (g) of this section for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if, the Administrator assumes [five certain assumptions].

Section 7(b)(2) describes a rate test designed to ensure that preference customers' firm power rates are no higher than rates calculated using five certain assumptions that remove specified effects of the Northwest Power Act. In settlement of many petitions to the U.S. Court of Appeals for the Ninth Circuit challenging BPA's implementation of the sections 7(b)(2) and 7(b)(3), the rate test has been replaced by provisions of the 2012 REP Settlement. REP-12-A-03. The Settlement provides a manner by which BPA can compute the amount of rate protection for preference customers in lieu of performing the rate test and provide an agreed-upon amount for REP benefits to investor-owned utilities.

Section 7(b)(3) in pertinent part states:

> Any amounts not charged to public body, cooperative, and Federal agency customers by reason of paragraph (2) of this subsection shall be recovered through supplemental rate charges for all other power sold by the Administrator to all customers.

Section 7(b)(3) directs that the cost of any rate protection afforded to preference customers is borne by all other BPA power sales. The rate protection does not extend to all PF customers; the public body, cooperative, and Federal agency customers receive the rate protection, but REP participants do not. Thus, to allow the cost reallocations due to the rate protection, the PF rate is bifurcated. The two resulting rates are the PF Public rate, which receives the rate protection, and the PF Exchange rate, which does not receive rate protection and bears its allocated share of the rate protection reallocation. The rate protection amount is collected though additional charges included in rates for all non-PF Public sales. The reallocation of rate protection costs is discussed in section 2.2.1 and 2.2.3.1. The 2012 REP Settlement retains the allocation of rate protection costs to all other rates through mechanisms specified in the contract.

### 1.2.3 Rate Design

Section 7(e) states:

> Nothing in this Act prohibits the administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or other rate forms.

BPA rates must follow the ratesetting directives of section 7, but, as characterized 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. This section reserves rate design (how the revenue is collected) to the Administrator. Rate design is discussed in section 2.3.

## 1.3 Regional Dialogue Policy Overview

In the Long-Term Regional Dialogue Policy (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 PF rate construct that provides each preference customer with a Contract High Water Mark (CHWM), which defines its right to buy power 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 contracts to all of its preference customers and investor-owned utilities. By December 5, 2008, all preference customers and three of seven investor-owned utilities (IOUs) signed the new contracts, which went into effect immediately. Power service under these contracts will commence at the start of fiscal year (FY) 2012, the first year of the rate period for which rates are being developed in this study. The other four investor-owned utilities are expected to sign new contracts; the rates described in this document assume such signings.

In November 2008, BPA issued its Tiered Rate Methodology (see section 1.4). Together, the CHWM contracts and the TRM provide long-term certainty to customers regarding their access to Tier 1 rate power and to BPA regarding its obligation to serve its customers' loads.

#### 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 the 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 will be recovered through Tier 1 rate charges for Load Shaping and Demand.

**Block.** The Block product provides a planned amount of firm power to meet a 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. No customers chose to purchase the Block-only product in this first election period.

**Slice/Block.** The Slice/Block product provides a combined sale of two distinct power products: (1) firm power for a 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

The TRM provides for a two-tiered PF Public rate design applicable to firm requirements power service for preference customers that signed a CHWM contract. The TRM establishes a predictable and durable means by which 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 rates 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. This Study describes the steps taken to tier the Priority Firm rates.

CHWMs, determined according to the TRM, are one basis (others are described later in this section) for determining 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 and is used to set each customer's initial eligibility to purchase power at Tier 1 rates. The individual CHWMs have been added to the respective CHWM contracts.

Related to the CHWM is the RHWM, which is an expression of the CHWM scaled to the expected output of resources identified as comprising the Tier 1 system. Because CHWMs were determined based on the expected output of Tier 1 system resources during FY 2012-2013, RHWMs for this period are equal to the CHWMs, as directed by the TRM. Each customer's RHWM for FY 2012-2013 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 that ensure, to the maximum extent possible, that customers purchasing 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.

The TRM was established in the TRM-12 rate case in 2008 and the supplementary TRM-12S rate case in 2009. For further details, see the resulting Records of Decision (RODs), TRM-12-A-01 and TRM-12S-A-01. The TRM sets forth a process to make changes to the TRM to address unintended consequences that put at risk the policy goals of the TRM. Prior to the start of the BP-12 rate proceeding, BPA and customers identified five unintended consequences and followed the TRM process to allow those changes to be proposed in the BP-12 rate proceeding.

The Administrator has adopted in the Final ROD all of the proposed changes to the TRM. The TRM, as revised in the BP-12 proceeding, is incorporated in the BP-12 Final Proposal as BP-12-A-03. See sections 1.2.2 and 2.2 of the Final ROD, BP-12-A-02.

## 1.5 Rate Options Supporting Regional Dialogue Products

### 1.5.1 Above-RHWM Load Service

A customer may choose to have its Above-RHWM load served as net requirements load by BPA at Tier 2 rates, consistent with the appropriate contractual notice and commitment requirements, which are summarized in the TRM. The Tier 2 rate alternatives currently available are the Tier 2 Load Growth rate and the Tier 2 Short-Term rate. The Tier 2 Vintage rate is a possible Tier 2 rate alternative that may be offered in the future. Additional information on the Tier 2 rate alternatives can be found in BPA's *Regional Dialogue Guidebook*. A description of rates for Tier 2 service can be found in section 3.1 of this document and in the PF-12 rate schedule.

Alternatively, a customer may add its own non-Federal resources to serve all or part of its Above-RHWM load. The notice and commitment periods for non-Federal resources or purchases are identical to those for purchases from BPA at the Tier 2 Short-Term rate.

### 1.5.2 Resource Support Services

BPA has developed a suite of Resource Support Services and related services for customers' non-Federal resources and for pricing service from BPA at Tier 2 rates. These services include Diurnal Flattening Service (DFS), Forced Outage Reserve Service (FORS), Secondary Crediting Service (SCS), Resource Remarketing Service (RRS), and Transmission Curtailment Management Service (TCMS). Depending on the type of resource and its output, RSS may be required to be purchased from either BPA or non-Federal sources for purposes of matching the resource to a planned shape and amount of load. These services enable BPA to cover the costs of following the variation between planned and actual customer resource amounts and to account for the impact that resource shapes and fluctuations have on BPA's cost to meet its customers' net requirement load. Additional information on the RSS suite of products can be found in PRS section 3.1.1.3, BPA's *Regional Dialogue Guidebook,* and the General Rate Schedule Provisions (GRSPs).

## 1.6 Rate Period High Water Marks

Each customer's RHWM helps to define that customer's maximum eligibility to purchase at Tier 1 rates for the rate period. The RHWM is determined based on the customer's CHWM and the RHWM Tier 1 System Capability (RT1SC). The determination of a customer's RHWM occurs outside of the rate case in the RHWM Process and is described in section 4.2.1 of the TRM. As noted in section 4.2 of the TRM, each customer's CHWM will be used as its RHWM for the FY 2012-2013 rate period.

BPA completed the CHWM Process in May 2011, and those CHWMs were used to calculate BP-12 rates. The one exception is Jefferson County Public Utility District (PUD). Jefferson County PUD is a new public customer, and its CHWM was not finalized in time to be used in the calculation of the BP-12 rates. As a result, BPA used its best available forecast of Jefferson County PUD's CHWM to calculate rates for the BP-12 Final Proposal. If Jefferson County PUD's final CHWM is ultimately different from the one used to calculate the BP-12 rates, BPA will adjust Jefferson County PUD's Tier 1 Cost Allocator (TOCA) and Contract Demand Quantity (CDQ).

### 1.6.1 RHWM Outputs

The RHWMs and related outputs of the RHWM Process, including RHWM Augmentation, RHWM Tier 1 System Capability, and forecast Net Requirements, are used to calculate billing determinants. Billing determinants impacted by the RHWMs include (1) a forecast of power sold at Load Shaping Rates, (2) the TOCAs, and (3) Unused RHWM. For the FY 2012-2013 rate period, the Above-RHWM load is not an output of the RHWM Process, as this amount was established when the Transition Period High Water Marks (THWM) were developed (see TRM section 4.3). For a description of how values calculated in the RHWM Process are used in the calculation of billing determinants, see PRS section 3.1.5.

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# 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 (see section 2.1) that 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 (see section 2.2) that 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 (see section 2.3) that produces tiered PF Public rates that collect the PF Public revenue requirement determined in the Rate Directives Step. This step also implements the rate design for other non-tiered rates.

## 2.1 Cost of Service Analysis Step

The COSA assigns responsibility for ("allocates") BPA's power revenue requirement (grouped into resource pools, also called cost pools) to the various classes of service (grouped into load pools, also called rate pools) based on the resources used to serve those loads, in compliance with statutory directives governing BPA's ratemaking and in accordance with generally accepted ratemaking principles. The COSA and the other ratemaking steps are programmed into a spreadsheet model, RAM2012, for purposes of calculating power rates.

### 2.1.1 Description of Cost of Service Analysis Modeling

The COSA modeling uses disaggregated customer load data from the source data used to produce the Power Loads and Resources Study. See PRS Documentation, Table 2.1.1. The disaggregated load data are aggregated into the PF rate pool (which consists 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. See section 1.2.

After the load data is input into the RAM2012, 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 which of the potential exchanging utilities has an Average System Cost (ASC) that is greater than the applicable Base PFx rate for the rate period. See section 2.2.1. Those utilities with higher ASCs will be participating in the REP 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 is used to calculate energy allocation factors (EAFs) that the COSA modeling will use to apportion costs among rate pools. 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 the principle 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 resources obtained by BPA under section 5(c) of the Northwest Power Act—that is, the exchange resources—and then with new resources, as needed. In this proposal, 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. See Documentation Table 2.3.1. The disaggregated cost data is 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 is performed in the Power Revenue Requirement Study and the Transmission Revenue Requirement Study, and only 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 section 2.1.3.2). As stated above, the exchange resource costs are calculated internal to the RAM2012. These 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 PFx transmission function costs.

In addition to exchange resource costs, the COSA modeling uses other costs that are internally generated by the RAM2012. 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.

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 the 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. These initial power rates are the starting point for the Rate Directives Step modeling in the RAM2012. See Documentation Table 2.3.10.

### 2.1.2 Loads and Resources

The sizes of the rate and resource pools are determined based on the results of the Power Loads and Resources Study. The process of allocating power costs begins with an examination of critical period firm loads and resources. After specific adjustments are made, RAM2012 calculates a ratemaking load-resource balance for each year of the rate period. From this ratemaking load-resource balance, RAM2012 determines service to each of the four rate pools (PF, NR, IP, and FPS) from each of the three resource pools (FBS, exchange, and new resources) for the rate period.

The Power Loads and Resources Study makes the distinction between PFp load to be served at a Tier 1 price and PFp load that is subject to Tier 2 pricing. The analogous distinction also holds for resources: the Power Loads and Resources Study identifies Tier 1 system resources and resources whose costs will be assigned to Tier 2 cost pools. Notwithstanding this distinction in the input data, the COSA allocations are performed with the tiered loads aggregated as a single PFp load and the newly-purchased resources combined into one FBS resource pool. The one exception to this combining of tiered inputs in the COSA calculations is that the consumer-owned utility (COU) Base PFx rate used to establish whether a COU is eligible to participate in the REP does not include any Tier 2 resource costs or any Tier 2 loads in its calculation. See Documentation Table 2.4.8. Table 2.2.1 of the Documentation shows the ratemaking energy loads and resources by pools.

The REP, created by section 5(c) of the Northwest Power Act, was designed to provide residential and small farm customers of Pacific Northwest utilities a form of access to low-cost

Federal power. Under the REP, BPA purchases power (exchange resources) from each participating utility at that utility's ASC. BPA establishes a utility's ASC through a formal ASC Review Process. Once a utility's ASC is established, BPA offers, in exchange, to sell an equivalent amount of electric power (exchange loads) to the utility at BPA's PFx rate. The exchange actually transfers no power to or from BPA, because the "exchange" is an accounting transaction in which dollars are exchanged, not electric power. However, to ensure proper cost allocations and rate determinations, RAM2012 models the REP as a purchase of power by BPA (priced at the participants' ASCs) and a simultaneous sale of power to the REP participant (priced at the participants' PF Exchange rates). Ratemaking under the 2012 REP Settlement retains the same establishment of exchange resources and exchange loads as has been done in ratemaking prior to the Settlement.

#### 2.1.2.1 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 its load obligations. In order to produce a power ratemaking load-resource balance that includes the amount of resource available to serve the rate pool loads, 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 ratemaking 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 size of the FBS with power at no added cost.

Finally, two obligations (the Southern Idaho exchange and the Sierra Pacific exchange) are transfers of power between BPA and another utility to serve BPA load in areas remote from BPA's transmission system. The BPA load that is ultimately served is included in PF loads, and retaining both the PF load and the transfer load would double-count BPA's obligation. Therefore, both the delivery of power included in loads and the receipt of an equal amount of power included in resources associated with these transfers, called locational exchanges, are removed. The ratemaking load-resource balance after adjustments is shown in Documentation Table 2.2.2.

**2.1.2.2 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), Federal agencies, and utilities participating in the REP. The 7(c) rate pool includes sales to BPA's direct-service industrial customers under contracts authorized by section 5(d) of the Northwest Power Act. The 7(f) rate pool includes three groupings: (1) power sold to COUs that is determined to serve new large single loads; (2) section 5(b) requirements power sold to the region's investor-owned utilities; 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 a formulaic rate established pursuant to section 7(c). 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, BPA allocates resource costs to IP loads in common with resource cost allocations to all other remaining *(i.e.,* non-PF) firm power sold. Thus, beginning in 1985 with the implementation of the directives of section 7(c)(1)(b) of the Northwest Power Act, BPA has had, 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 its formulaic basis.

#### 2.1.2.3 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.

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 eligible REP participants and to sell an equivalent amount of electric power to the participant.

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

#### 2.1.2.4 Order of Resource Service to Load Pools

As noted in section 2.1.1, section 7(b)(1) of the Northwest Power Act specifies how resource costs must be allocated to the Priority Firm Power customer class. That is, 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 sets forth 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 Resources Firm Power, and Firm Power Products and Services contracts.

For the BP-12 rates, the PF load (which at this point consists both of 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. Because the remaining PF load is less than the total exchange resource under section 5(c), a pro rata share of exchange resource costs is allocated to the PF rate pool in the amount necessary for the exchange resource to serve the PF load not served by FBS resources. The remaining exchange resources and all new resources and their attendant costs are allocated to all other firm load.

#### 2.1.2.5 Energy Allocation Factors

Energy allocation factors are calculated for each resource pool–rate pool combination by dividing the amount of annual energy load in each rate pool served from each resource pool. The annual EAFs for each resource cost pool as well as for the various rate directive steps are shown in Documentation Table 2.2.3. The Total Usage and Conservation allocation factors assume a pro rata allocation of costs to all firm loads. For example, the Total Usage EAF for costs allocated to the PF load pool is equal to the ratio of PF load to total firm load. The Total Usage and Conservation EAFs are used to allocate section 7(g) costs and rate directive allocation adjustments to all firm energy loads.

### 2.1.3 Ratemaking Costs

For ratemaking purposes BPA's costs are allocated to six cost pools. The first three cost pools are associated with BPA's resource pools: FBS costs, exchange resource costs, and new resource costs. These resource-related costs are allocated in accordance with sections 7(b)(1) and 7(f) of the Northwest Power Act. The other three cost pools—conservation costs, BPA program costs, and power-related transmission costs—are allocated in accordance with section 7(g). In addition to these cost pools, the PF revenue requirement is adjusted upward due to the expected revenue shortfall caused by the implementation of the Low Density Discount and the Irrigation Rate Discount. See sections 2.1.3.3 and 2.1.3.4.

#### 2.1.3.1 Revenue Requirement

The Bonneville Project Act, the Flood Control Act of 1944, the Transmission System Act, and the Northwest Power Act provide guidance regarding BPA ratemaking. The Northwest Power Act and the other statutes, using somewhat varying language, require BPA to set rates that are sufficient to recover, in accordance with sound business principles, the costs of acquiring, conserving, and transmitting electric power, including amortization of the Federal investment in the FCRPS over a reasonable period of years, and the other costs and expenses incurred by the Administrator. See section 1.2.

The Power Revenue Requirement Study is based on power revenue and cost estimates for a two-year rate period, FY 2012-2013. 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. RAM2012 uses key code mapping to allocate all costs into both the COSA cost pools and the TRM cost pools. Because of the different purposes of the COSA and the TRM, the COSA cost pools are not related to 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 forecast cost of system augmentation purchases is calculated using prices under 1937 water conditions as determined in the Power Risk and Market Price Study. The expense estimate for system augmentation purchases is based on the application of market prices for the 50 games of the Power Risk and Market Price Study associated with 1937 water conditions. 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. The costs of balancing power purchases under 3,500 games of different risk conditions are calculated by the Risk Analysis Model (RiskMod). In the Power Risk and Market Price Study, average balancing purchase quantities are computed and valued in RiskMod against median total balancing purchase costs based upon a Monte Carlo simulation of 3,500 games. The average balancing purchase quantities and median expense dollars are combined to derive an expected balancing purchase price for balancing purchases from RiskMod. These prices and quantities are then passed to RAM2012 to compute balancing purchase costs. Balancing power 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.

#### 2.1.3.2 Functionalization of Exchange Resource Costs

In the COSA, exchange resource costs are based on participating utilities' ASCs and their exchange power sales to BPA. ASCs include the cost of power and transmission services associated with serving a participating utility's total retail load. By definition, exchange resource sales to BPA equal the exchange sales by BPA. The rate directives 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 PF Exchange 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.

#### 2.1.3.3 Low Density Discount

Section 7(d)(1) of the Northwest Power Act provides that, in order to avoid adverse impacts on retail rates of BPA's customers with low system densities, BPA shall apply, to the extent appropriate, discounts to the rate or rates for such customers.

The cost of providing the discount is computed in RAM2012 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. These offsets are computed in the TRM Billing Determinants Model, which is a separate module of RAM2012.

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.

#### 2.1.3.4 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 customer power bills. The Irrigation Rate Discount rate is calculated in RAM2012, as described in section 3.1.11.1. The cost of the discount is computed in RAM2012 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.

#### 2.1.3.5 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.

##### 2.1.3.5.1 Section 7(b)(1) costs

Section 7(b)(1) costs are associated with the resources necessary to serve PF load, including the PFp load and the PFx load. For the BP-12 rates, these resources are 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.

##### 2.1.3.5.2 Section 7(f) Costs

Section 7(f) costs are associated with the resources necessary to serve non-PF load, including IP, NR, and FPS loads. For the BP-12 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.

**2.1.3.5.3 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) debt service for 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).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 defending legal challenges to BPA's ratemaking decisions. Development of these power program costs occurs in the Integrated Program Review, as described in the Power Revenue Requirement Study, section 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 GTAs 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. Transmission costs are allocated to all rate pools based on the Total Usage EAFs. See Documentation Table 2.3.4.3.

#### 2.1.3.6 Planned Net Revenues for Risk

PNRR is an amount of net revenues required 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. Under the ratemaking methodology, the amount of PNRR is the result of an iterative process between the RAM2012, RiskMod, Non-Operating Risk Model (NORM), and ToolKit models. See Power Risk and Market Price Study section 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 RiskMod 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-12 rates, no iterative process is required to determine rate levels.

### 2.1.4 Revenue Credits

#### 2.1.4.1 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.

#### 2.1.4.2 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, section 2.6.1, and supplied to RAM2012. 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.

#### 2.1.4.3 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 and locational 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.

#### 2.1.4.4 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. See Documentation Table 2.3.6.

#### 2.1.4.5 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.

#### 2.1.4.6 Miscellaneous Revenues

Miscellaneous revenues are described in section 4.1.8. These revenues are allocated to all firm load through the General Cost EAFs. See Documentation Table 2.3.6.

#### 2.1.4.7 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 $7.50 for FY 2012 and $8.00 for FY 2013 and renewable project output included in the FBS and new resources 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.

### 2.1.4.8 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 Generation Inputs Study explains and documents these credits. Revenues associated with Generation Inputs, Network Wind Shaping, and RSS 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.

### 2.1.4.9 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 described above 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 3,500 games of different risk conditions are calculated by RiskMod. Power Risk and Market Price Study, section 2.2.3; see also Documentation Table 2.3.8. Consistent with the Power Risk and Market Price Study, average secondary sales quantities are computed and valued against median total secondary revenues based upon a Monte Carlo simulation of 3,500 games. The average secondary sales quantities and median revenue dollars are combined to derive an expected sales price for secondary energy from RiskMod. These prices and quantities are then passed to RAM2012 to compute secondary energy revenues.

The secondary revenues projected in RiskMod 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 RiskMod 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.

**2.1.5 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 a comparison is made between the costs allocated to the sales of this firm power and the revenues received from the sales of such power. The expected revenue forecast from the sale of firm power, 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. See Documentation Table 2.3.9.

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

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.

### 2.2.1 Description of 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. 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. All costs and credits have been allocated to rate pools in the COSA. The Rate Directives Step will adjust 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.

#### 2.2.1.1 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, Appendix A of this Study. See Documentation Table 2.4.1. Monthly and diurnally differentiated PF melded rates are calculated as described in section 3.1.12. See Documentation Tables 2.4.2 and 2.4.3. Because the IP-PF Link calculation consists of maintaining a set relationship between the levels of the IP and PF rates for each year while simultaneously allocating costs between the two rates, and to avoid multiple iterations, RAM2012 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, RAM2012 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-12) IP rate at this point in the modeling is not below the IP floor rate, and no floor rate adjustment is needed.

#### 2.2.1.2 Determine 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 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.

#### 2.2.1.3 Calculate 7(b)(2) Rate Protection and 7(b)(3) Reallocations

Once these steps are complete, 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-12 rates are calculated pursuant to a settlement of the outstanding litigation associated with the REP and the section 7(b)(2) rate test. This settlement effectively implements the section 7(b)(2) rate test through other calculations that provide preference customers with an amount of rate protection based on the express settlement amount of IOU REP benefits, any COU REP benefits for qualified REP participants, and the IP and NR rates as specified in the REP Settlement.

The rate modeling 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 rates 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 determining a ratio of (i) the IOU Scheduled Amounts plus COU Settlement 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 2.4.12. After the utility-specific PFx rates are calculated, the utility-specific REP benefits are calculated and summed. See Documentation Table 2.4.12.

A second part of rate protection is calculated and allocated to the IP and NR rate pools, the REP Surcharge. 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. This 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 2.4.14. This amount is allocated to the IP and NR rate pools.

The RAM2012 REP Settlement modeling explicitly adjusts dollars between the PFp, PFx, IP, and NR rate pools. The REP Settlement rate protection allocations have the effect of increasing the IP, NR, and PFx rates while decreasing the PFp rate. See Documentation Table 2.4.15.

#### 2.2.1.4 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.

### 2.2.2 IP Rate

The IP rate is based on 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" is defined pursuant to section 7(c)(2) 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.

#### 2.2.2.1 Applicable Wholesale Rate

The applicable wholesale rate is calculated as the rates 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 NLSLs). 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.

#### 2.2.2.2 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.

#### 2.2.2.3 IP-PF Link 7(c)(2) Adjustment

The IP-PF Link 7(c)(2) adjustment is necessary to account 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.

#### 2.2.2.4 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 2012-2013) 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 the proposed IP rate revenue is greater than the floor rate revenue, no floor rate adjustment is necessary. See Documentation Tables 2.4.6 and 2.4.7.

### 2.2.3 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-12 rates, the rate test was performed in the assessment of the 2012 REP Settlement. The Settlement was found to be in compliance with the rate test and rates are established pursuant to the Settlement.

## 2.3 Rate Design Step

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 would 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 constant annual energy rate for PFp Tier 2 rates and the PFx rate.

### 2.3.1 Description of Rate Design Step Modeling

Based on the results of the Rate Directives Step, RAM2012 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 3.1.12. 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.

#### 2.3.1.1 TRM Rate Modeling

Additional processing is required before the PFp rate design can be implemented. 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 different manner than the COSA. RAM2012 accomplishes this different 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 RAM2012, 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 RAM2012. 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 have this load served at the Load Shaping rate.)

- Secondary energy revenues credit.
- Revenues allocated for Unused RHWMs. See section 3.1.3.2.
- Demand and Load Shaping revenues. See sections 3.1.2.4 and 3.1.2.3.
- Cost of Network real power losses on sales to non-Slice preference customers. See section 3.1.3.1.
- Tier 2 overhead costs and other cost assignments. See section 3.1.4.1.

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

### 2.3.2 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 and Load Growth 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 2.5.5.4.

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 also recognize that, even though the ratesetting methodology described in this section 2 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.

**2.3.2.1 Composite Cost Pool**

Except for costs and credits that are 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.

**2.3.2.2 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.

**2.3.2.3 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-12 rates there are no costs allocated to this cost pool.

**2.3.2.4 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 are supportive in part of 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 2.5.5.2.

## 2.4 Rate Modeling Iterations

Several iterations—both internally within RAM2012 and externally between other models and RAM2012—are required before the ratesetting process is finalized. 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 Average System Cost. 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. RAM2012 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 sections 2.1.3.3 and 2.1.3.4) 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, since final charges are in part dependent 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, RAM2012 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 RAM2012. Many of these dependencies have been integrated within RAM2012, 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 RAM2012. In addition, the amount of Refund Amount that the COU will receive is also dependent upon the COU's 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 RAM2012 and the ASC forecast model. Revised ASCs are included in RAM2012, and rate levels are recomputed until the results converge.

#### 2.4.2.2 Risk Analysis and Mitigation: PNRR

PNRR is an amount of net revenues required from power rates to ensure that cash flows from proposed rates meet BPA's Treasury Payment Probability (TPP) standard. The amount of PNRR is the result of an iterative process among four models: RAM2012, RiskMod, NORM, and ToolKit. See Power Risk and Market Price Study section 3.3. The iterative process is initiated with a seed value for PNRR in revenue requirement used in RAM2012. The resultant rates are used in RiskMod and NORM to produce distributions of net revenues. These distributions are then used in the ToolKit to produce a new PNRR value for the RAM2012 revenue requirement. See Documentation section 2. Because PNRR is determined to be zero, no iterative process is required to determine rate levels for the BP-12 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 2012-2013. 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 revenue test is described in section 4 of this Study and in the Power Revenue Requirement Study, section 3.3. The power rates placed in effect October 1, 2010, are used in the calculation of revenue at current rates for FY 2012-2013, using the load forecast from the Power Loads and Resources Study.

The rates as computed in RAM2012 are applied to the same loads to create a revenue forecast at proposed rates for FY 2012-2013. 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, section 4, 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-12 rates are sufficient to recover the revenue requirement, and no further rate adjustment is needed. See Power Revenue Requirement Study section 4.

## 3. RATE DESIGN

As described in section 1.2.3, the Administrator retains a considerable amount of discretion in designing rates, as long as the rates meet the other requirements of Northwest Power Act section 7.

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 Products and Services. Rate design does not change the amount of the revenue requirement that is allocated to each of the five rate pools. Rather, rate design determines how the revenue requirement is to be collected through rates for each of the five rate pools. One purpose of rate design is to target the revenue collection within a particular rate pool and to distinguish between different types of service and power consumption of individual wholesale power customers. Another purpose is to provide price signals to customers to encourage more-efficient power usage and differentiate between the relative market value of the products and services BPA offers to its customers.

This section of the Power Rates Study describes the rate design for peaking capacity use, time-of-day use, and seasonal use of power purchased from BPA under its Priority Firm Power (PF-12), Industrial Firm Power (IP-12), and New Resources Firm Power (NR-12) rate schedules.

There are three Priority Firm Power rates: the PFp rate, the PFx rate, and the Priority Firm Melded rate. PFp rate design is applicable to purchases by public bodies, cooperatives, and Federal agencies pursuant to CHWM contracts. The PFx rate design is applicable to purchases by utilities pursuant to a Residential Purchase and Sale Agreement (eligible COUs) or Residential Exchange Program Settlement Implementation Agreement (eligible IOUs). The PF

Melded rate design is applicable to purchases by public bodies, cooperatives, and Federal agencies pursuant to power sales contracts other than a CHWM contract. No sales under the PF Melded rate are forecast during the rate period, FY 2012-2013.

The PFp rate design is based on the design set forth in the Tiered Rate Methodology, BP-12-A-03. The TRM established a rate design for the PFp rate schedule to be used for power sales under BPA's CHWM contracts.

The PFx rate schedule is also described in this section. Due to the annual design of the Residential Exchange Program, application of a rate design that included rate differentiation within the PFx rate schedule for peaking capacity use, time-of-day use, and seasonal use of power purchased from BPA was deemed unnecessary for the PFx rate schedule.

The TRM did not establish a rate design for the PFx, IP, and NR rate schedules. The rate design for IP and NR service is described in this Study, and the specific rates are set forth in the Power Rate Schedules, BP-12-A-02B. Certain PFp design elements adopted in the TRM are used in the IP-12 and NR-12 rate design, in particular the method for scaling Energy rates from the market forecast and the general method for calculating the Demand billing determinant.

### 3.1 Priority Firm Public Rate Design

As described in the TRM, the PFp rate design includes two tiers. The tiering of the rates is a ratemaking construct that allocates the costs and credits functionalized to power; it is not an allocation of power to customers. 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. 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.

In addition to creating the Tier 1 and Tier 2 cost pools, the TRM also determined a new rate design for the Tier 1 rates. Tier 1 rates include three customer charges: the Composite Customer Charge, the Non-Slice Customer Charge, and the Slice Customer Charge. These charges recover the costs allocated to their respective cost pools. The rate for each of the customer charges is a dollar amount per each one percentage of the billing determinant. For each customer charge, each customer's billing determinant will respectively be its Tier 1 Cost Allocator (TOCA), Non-Slice TOCA, or Slice Percentage. In addition to the customer charges, the Tier 1 rates include 24 monthly/diurnal Load Shaping rates and a Demand Charge with 12 monthly Demand rates.

Tier 2 rates coincide with the Tier 2 rate options elected by customers to meet their Above-RHWM Load obligation. In PF-12 these are the Short-Term and Load Growth Tier 2 rates.

BPA calculated two other rates based on the TRM "component" rates. First is the PFp Tier 1 Equivalent Rate for use in contracts that have rates that are tied to a traditional PF HLH/LLH rate design. Second, a PFp Melded rate schedule is included should BPA need to serve load of a preference customer that does not have a CHWM Contract.

### 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 2012-2013 rate period there are two Tier 2 cost pools, Load Growth and Short-Term. The method by which costs and credits are allocated among the five PFp cost pools is directed 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 Load Growth and Short-Term cost pools include all costs and credits that are attributable to the resources and services necessary for load served at a Tier 2 rate. Additional detail on these cost pools is found in section 3.1.7 below.

To calculate the Tier 1 and Tier 2 rates, all costs and credits are allocated to the appropriate cost pools; all costs functionalized to generation are allocated to one of the five PFp cost pools (Composite, Non-Slice, Slice, Tier 2 Load Growth, and Tier 2 Short-Term). As described in section 2.1 above, the same costs and credits have also been allocated to the PF rate pool and other rate pools: IP, NR, and FPS. To account for the costs and credits allocated to these other rate pools, the revenues recoverable from the other rate pools have reduced the costs allocated to the Composite cost pool. A demonstration is included in RAM2012 that shows that the revenue requirement allocated to the PFp rate pools in the COSA equals the costs and credits allocated to the PFp cost pools after the reductions from the other rate pools. See Documentation Tables 2.5.6.1 and 2.5.6.2.

Once costs and rate design revenue credits have been balanced with the revenue requirement, to the extent necessary additional adjustments to the PFp cost pools are made 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 overall revenue requirement or the cost allocations among PF, IP, NR, and FPS. These rate design adjustments include three adjustments made within Tier 1 (section 3.1.3) and two adjustments 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 two adjustments made between Tier 1 and Tier 2 are the Tier 2 Overhead Adjustment and the Tier 2 Balancing Adjustment.  The complete allocation of costs with all revenue credits and adjustments for the five cost pools can be found in Documentation Table 2.3.5.

### 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 collectable from the sale of Resource Support Services.  The Non-Slice cost pool includes a credit for forecast revenue collectable through the Load Shaping, Demand, and Resource Shaping charges.  All of these rate design credits are necessary to ensure that the PFp rates do not overcollect 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 five RSS options that generate revenue from preference customers.  Revenue received from RSS is credited to the Composite cost pool.  For transparency purposes, BPA committed in the TRM to apply 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 either through an RSS adder to the system augmentation cost or an RSS cost within a Tier 2 cost pool.

The total annual RSS revenue credit for FY 2012-2013 can be found 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 revenue 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 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 section 8. In these situations, the source of the RSC revenue credit is provided either through an RSC adder to the system augmentation cost or through an RSC adder within a Tier 2 cost pool. The forecast annual RSC revenue credit for FY 2012-2013 can be found 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 is applicable 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. Thus, as stated in the TRM, 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 Demand charge is designed to send a price signal to a limited portion of a customer's overall demand on BPA and is applicable to customers purchasing Load Following and Block with Shaping Capacity products. Thus, forecast revenue from the Demand charge is credited to the Non-Slice cost pool by means of the Demand 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 equivalent debit to the Non-Slice cost pool based on Non-Slice transmission losses. The Transmission Loss Adjustments account for different accounting of transmission losses to 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 2.5.7.1). The calculation and result of the Transmission Loss Adjustments can be found 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 while the Secondary Revenue and Balancing Purchases are part of the Non-Slice cost pool. In order to share the entire benefit of Unused RHWM to all customers, both 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. One purpose 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 this change in balancing purchase costs associated with this 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 Table 2.5.2 of Documentation 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**

Balancing augmentation load is either (1) Above-RHWM load that is forecast to be served at Load Shaping rates, rather than at Tier 2 rates or with a non-Federal resource (net positive load shaping billing determinants) or (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).

The first condition occurs when Above-RHWM load is forecast to be served at load shaping rates either 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 when Above-RHWM load is locked down and the load forecast is updated during the rate case to reflect the forecast of a larger load.

The 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 locked down and the load forecast is updated during the rate case to reflect the forecast of a smaller load.

When the first condition exists 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.

When the second condition exists, 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.

In the first condition, the sum of Load Shaping billing determinants is 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. In the second condition, the sum of the Load Shaping billing determinants is negative. The Balancing Augmentation Load Adjustments to the Composite and Non-Slice cost pools are calculated as the greater of the sum of the Load Shaping billing determinants 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.

Due to the forecast sum of the Load Shaping billing determinants being negative in both FY 2012 and FY 2013, the Balancing Augmentation Adjustment line item in the Composite cost pool is a debit, and the Balancing Augmentation Adjustment line item in the Non-Slice cost pool is an equal credit. See Documentation Table 2.5.5.

### 3.1.4 Rate Design Adjustments Made Between Tier 1 and Tier 2 Cost Pools

#### 3.1.4.1 Tier 2 Overhead Adjustment

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 section 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. This Tier 2 Overhead Adjustment for FY 2012-2013 can be found in Documentation Table 3.2.

#### 3.1.4.2 Tier 2 Balancing Adjustments

Purchases to serve Above-RHWM load are made in whole average megawatts. Tier 2 purchase amounts are calculated in average kilowatts. This results in a fractional megawatt surplus in the FY 2012 Short-Term rate pool and fractional megawatt deficits in the FY 2013 Short-Term and Load Growth rate pools. The Tier 2 Balancing Revenue Adjustment credits or debits a Tier 2 cost pool when the power purchases do not exactly equal the sales at the Tier 2 rate.

When Tier 2 purchases exceed (or are less than) Tier 2 load obligations (Tier 2 imbalance), a credit (or debit) is applied to the applicable Tier 2 cost pool, and an equal debit (or credit) is applied to the Composite cost pool, the Non-Slice cost pool, or a combination of the Composite and Non-Slice cost pools. The respective credits and debits are calculated by multiplying either the annual augmentation price or the flat annual equivalent of the AURORA market price forecast for each fiscal year (see Power Risk and Market Price Study Documentation, Table 17) by the difference between sales at the Tier 2 rate and the megawatthours purchased to meet that load. The augmentation price is used in the calculation when the Tier 2 imbalance changes the amount of augmentation expense included in the Composite cost pool. Conversely, the AURORA market price is used when the Tier 2 imbalance changes the amount of firm surplus in the Non-Slice cost pool. See Documentation Table 3.3 for the flat annual equivalent of the AURORA market price forecast, the annual augmentation price, and the annual augmentation amount. Both the Composite and Non-Slice cost pools can be credited or debited if there is a Tier 2 imbalance and the total amount of augmentation is less than the Tier 2 imbalance.

Due to a zero augmentation amount in FY 2012 and a positive augmentation amount in FY 2013, the Tier 2 Balancing Adjustment impacts the firm surplus amount in FY 2012 and the augmentation amount in FY 2013. Therefore, the AURORA market price was used to calculate the Tier 2 Balancing Adjustment for FY 2012, and the annual augmentation price was used to calculate the Tier 2 Balancing Adjustment for FY 2013. See Documentation Table 3.2.

### 3.1.5 PFp Tier 1 Billing Determinants

#### 3.1.5.1 Tier 1 Cost Allocator

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 5 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 can be found in Table 1, and the sum of TOCAs used for FY 2012-2013 can be found in Documentation Table 2.5.5.3.

#### 3.1.5.2 Non-Slice TOCA

The Non-Slice TOCA is the billing determinant that is 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 5 decimal places. The forecast sum of Non-Slice TOCAs used for FY 2012-2013 can be found in Documentation Table 2.5.5.3.

#### 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 Slice Percentage in Exhibit K of each Slice customer's CHWM contract is updated each year and can be adjusted, pursuant to section 3.6 of the TRM. The Slice Percentage is rounded to 5 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.

A customer's System Shaped Load is calculated as the RHWM Tier 1 System Capability (see section 1.6) 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 less the customer's System Shaped Load for the same monthly/diurnal period.

**Monthly/Diurnal RHWM Tier 1 System Capability.** The TRM specifies 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. This 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, because each February has a unique value for each HLH and LLH period. See GRSP II.Q.

#### 3.1.5.5 Demand Billing Determinant

The Demand billing determinant is applicable 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 calculating 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 customers' CHWM contract.

The Super Peak Credit will be determined pursuant to a customer's CHWM contract. The Super Peak Period hours for FY 2012-2013 are defined in the GRSPs as follows (HE = Hour Ending):

| | |
|---|---|
| October - February | HE 8 through HE 10 and HE 18 through HE 20 |
| March - May | HE 7 through HE 12 |
| June - September | HE 14 through HE 19 |

### 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 2.5.5.3.

#### 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, section 2.4. Also see Documentation Table 3.4.

##### 3.1.6.2.1 Load Shaping True-Up

The Load Shaping True-Up is an adjustment to the Load Shaping charge and is necessary to ensure that 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 will be applicable. The Load Shaping Charge True-Up 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 detailed process for calculating the Load Shaping True-Up rate is set forth in section 5.2.4.2 of the TRM, and the rate is specified in GRSP II.I.

**Special Implementation Provision for Load Shaping True-Up.** Special implementation provisions 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 is designed to solve a transitional implementation issue caused by setting Above-RHWM load based on a different forecast than is used to determine a customer's TOCA. This implementation provision is necessary in this rate period because Above-RHWM Load was determined in 2009 and the calculation of a customer's TOCA occurred in 2011. 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.

First, if the Annual Deviation calculation of the Load Shaping Charge True-up is negative or equal to 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 (1) the customer's Above-RHWM load, or (2) the Above-RHWM load less the absolute value of the Annual Deviation amount, or (3) the Above Forecast amount, whichever is the smallest. 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 less the Annual Deviation amount.

#### 3.1.6.3 Tier 1 Demand Rates

The Demand rates are based upon the annual fixed costs (capital and O&M) of the marginal capacity resource, an LMS-100 combustion turbine, as determined by the Northwest Power and Conservation Council's Microfin model 14.2.11 used in the Council's Sixth Power Plan. The Microfin model is used to obtain an estimate for the all-in capital costs in 2012 dollars of an

LMS-100 with a 2012 in-service date. The all-in capital cost under these specifications is $1,081/kW. See Documentation Table 3.5.

The projected debt payment on the $1,081/kW fixed capital costs is estimated at $115.48/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 2012 Third-Party Tax-Exempt 30-Year Borrowing Rate Forecast. See FY 2011 Common Agency Assumptions memo in the Power Revenue Requirement Documentation, chapter 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 2006 estimate of $8/kW/yr and is escalated to 2012 and 2013 dollars using the 2005 to 2010 average (5-year) rate of 2.05 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 $9.12/kW/yr.

Insurance and fixed fuel are also included in the calculation of the Demand rate. The annual insurance cost of $2.61/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 $35.73/kW/yr. The fixed fuel cost is estimated using Microfin's vintaged heat rate of 8,738 Btu/kWh and applied to the average of the existing and new Pacific Northwest East (PNWE) fixed fuel costs for the applicable fiscal year. Lastly, an offsetting revenue credit was applied equal to 10 percent for the resale of firm pipeline rights.

The average annual expense is $115.48/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 3.5 and the Power Rate Schedules, BP-12-A-02B, *e.g.*, section 2.1.2.1.

#### 3.1.6.4 PFp Tier 1 Equivalent Rates

The PFp Tier 1 Equivalent rates consist of 12 HLH and 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 can be found in Documentation Table 2.5.7.5. The Demand rates are equal to the Tier 1 Demand rates.

### 3.1.7 PFp Tier 2 Cost Pool

There are two Tier 2 rates—the Short-Term rate and the Load Growth rate. Costs allocated to the aggregate Tier 2 cost pool are further allocated to the Short-Term and the Load Growth cost pools. For the rate period, those costs are the actual costs associated with the flat-block energy purchases at the transacted amounts and prices. Costs for Tier 2 Overhead Adjustment, Tier 2 Balancing Adjustment, and scheduling services are added to these cost pools and are described below in the following sections.

#### 3.1.7.1 Tier 2 Overhead Cost Adder

Section 6.3.3 of the TRM 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 3.6. The rate period total of these overhead costs is divided by BPA's total forecast of revenue-producing (PFp, IP, NR, FPS, Downstream Benefits and

Pumping Power, Pre-Subscription, Generation Inputs for Ancillary and Other Services Revenue, and Secondary sales) energy sales, which results in a $1.17/MWh adder 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 and Load Growth) 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 section 3.1.4.1 above. The specific cost and sales values used in these calculations can be found in Documentation Table 3.2.

#### 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 2009 and FY 2010 to produce a yearly $/MWh value. This calculation is summarized in Table 3.3 of the Documentation. Inputs to this calculation are also included in Documentation Table 3.7. This value is multiplied by the amount of planned Tier 2 sales in each year for each Tier 2 alternative (Short-Term and Load Growth) to produce the annual cost value 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 section 3.1.2.1 above. The calculated costs assigned to each cost pool in each year can be found in Documentation Tables 3.8 and 3.9.

#### 3.1.7.3 Tier 2 BPA Market Purchases

BPA made a total of three purchases for Tier 2 rate service for the FY 2012-2013 rate period. The power amounts are roughly equal to the Tier 2 load obligation for each year plus the real power losses required to deliver the power to the purchasers. Purchase costs for FY 2012 are allocated entirely to the Short-Term cost pool. Purchase costs for FY 2013 are allocated on a pro rata load basis between the two Tier 2 cost pools for FY 2013. The average megawatt amounts and their associated power purchase prices are summarized in Documentation Table 3.10.

#### 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, 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 2012-2013 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 its Above-RHWM load. Each customer's Tier 2 rate service amount is contractually established for FY 2012-2013, as summarized in Table 3.11 of the Documentation. Because there are no purchases of Load Growth service in FY 2012, no costs are allocated to the Load Growth cost pool for FY 2012.

### 3.1.9 Tier 2 Rates

Based on the annual average megawatt load obligations for each Tier 2 rate alternative (Short-Term and Load Growth) 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 and 3.10. 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 (Tier 2 Balancing Adjustment).

#### 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, 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 Power Services point of delivery for the market purchases allocated to the Tier 2 cost pools. The adjustment is described in GRSP II.S.

### 3.1.10 Calculating Charges to Reduce Tier 2 Purchase Amounts

Section 2.4.2 of Exhibit C of the Load Following CHWM contract provides customers with an opportunity to reduce the purchase amounts supplied by BPA at the Tier 2 Short-Term rate, if notice is provided by October 31 of a Rate Case Year, which was October 31, 2010, for the BP-12 rate period. If a customer makes this election, BPA may levy charges to cover costs that BPA is obligated to pay and is not able 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. Two customers elected to reduce their Short-Term rate purchase amounts for the FY 2012-2013 period, and one customer elected to reduce its Short-Term rate purchase amounts in FY 2013. This amounted to 0.166 aMW of total reduced service in FY 2012 and 0.792 aMW in FY 2013. The notices were provided prior to BPA making any purchases to meet its Short-Term rate load obligations, so BPA has not incurred any costs due to these purchase reductions, and therefore there are no costs that need to be recovered through such charges.

### 3.1.11 PFp Irrigation Rate Discount

The Irrigation Rate Discount 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-12 rate period. See GRSP II.H.

#### 3.1.11.1 Irrigation Rate Discount Rate

The TRM establishes the method for calculating the IRD rate.  The process begins with a fixed Irrigation Rate Mitigation Program (IRMP) percentage equal to one minus the ratio of (1) the sum of the IRMP participants' estimated charges at the FPS rates paid under IRMP for FY 2009 to (2) the sum of the IRMP participants' estimated charges that would have occurred under May through August HLH and LLH PF-07 Energy rates for FY 2009 adjusted for any applicable discounts such as the LDD.  See TRM, BP-12-A-03, at section 10.3.  See Documentation Tables 3.12 and 3.13.

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 MWh), to derive a dollars per MWh discount.  The applicable Low Density Discount is calculated as the weighted average eligible Low Density Discount of irrigation customers weighted with eligible irrigation loads.  See Documentation Table 3.14.

Forecast revenue for irrigation loads will be calculated using an IRD TOCA derived by dividing the sum of the irrigation loads (expressed in aMW) by the sum of all RHWMs.  This IRD TOCA will be applied consistent with Section 5 of the TRM for calculation of forecast irrigation revenues from the Composite Customer Charge, the Non-Slice Customer Charge, and the Load Shaping Charge.  This discount will be seasonally available to qualifying loads during May, June, July, August, and September. See TRM, BP-12-A-03 at 93.  The calculation is shown on Table 2.3.3 of Documentation.

#### 3.1.11.2 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 rate. The amount of irrigation credit the customer would receive is limited to the lesser of a customer's Tier 1 energy purchase or its eligible irrigation load amounts in the customer's CHWM contract.

#### 3.1.11.3 Irrigation Rate Discount True-Up

At the end of each irrigation season, customers with eligible irrigation load will send to 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 to BPA 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 H.2.

### 3.1.12 PFp Melded Rates (Non-Tiered Rate)

Melded PF Public rates are included in the PF rate schedule. The PFp Melded rates consist of 12 HLH and 12 LLH Energy rates and 12 Demand rates. The PFp Melded Energy rates are equal to the 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. This $/MWh value is the PFp Melded Equivalent Energy Scalar, which is also used in the Slice True-Up to determine the actual DSI revenue credit. This calculation is shown in Documentation Table 2.5.7.2. The applicable Demand rates are equal to the PFp Tier 1 Demand rates.

The PFp Melded Energy rates are used to shape and set the level of the IP Energy rates, as described in section 3.3.1.

#### 3.1.13 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.

RSS is also applied to Federal resource acquisitions to make them financially equivalent to a flat block, if necessary. See TRM section 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 TRM section 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 in this rate period 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, and the method for doing so is described above in section 3.1.7.2. Costs for TCMS events associated with Tier 2 rate service are recovered through a mechanism known as the Tier 2 Rate TCMS Adjustment, described above in section 3.1.9.1.

##### 3.1.13.1 RSS Rates

RSS rates are included in both the PF rate schedule and the FPS rate schedule. The rates described here under the PFp section include Diurnal Flattening Service energy and capacity rates, Resource Shaping rates and adjustment, Secondary Crediting Service shortfall and secondary energy rates, and Secondary Crediting Service Administrative Fee rate. The rates described under the FPS section below include Forced Outage Reserve Service energy and capacity rates, TSS rate, and TCMS rate. 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 3.2.

### 3.1.13.2 RSS Diurnal Flattening Service, Resource Shaping Charge, and Resource Shaping Charge Adjustment

#### 3.1.13.2.1 Diurnal Flattening Service (DFS)

DFS is an optional service that financially converts the output of a variable, non-dispatchable resource into one that is equivalent to a flat amount of power, within each diurnal period of a month. When DFS charges are coupled with the Resource Shaping Charges, the variable generating resource is financially converted to one that is equivalent to a flat annual block of power. BPA selected a flat annual block of power as the benchmark shape to which to compare new non-Federal resources and Tier 2 purchases.

The RSS module of RAM calculates a unique set of rates and charges for each resource to which DFS is applied. Illustrative model runs for example resources are included in the Documentation to show how the various charges and rates would be calculated for a sample resource. See Documentation, Tables 3.15–3.22. Also included in the Documentation are the final rates and charges calculated for the customers that have requested DFS for their resources. See Documentation Table 3.23. The PF-12 rate schedule includes a section on the general rate application of the DFS-related charges. See PF-12 Rate Schedule, section 5.1. 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.P.

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 out 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 generation forecast error.

**3.1.13.2.2 DFS Capacity Charge**

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

**DFS 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. Because planned outages are not included in the FY 2009 data, a planned outage adjustment is not necessary. Therefore, 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 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 (i) the monthly DFS Capacity rates multiplied by (ii) the monthly DFS billing determinants

or

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

The result is then divided by 12 to calculate a flat monthly charge that will be specified in Exhibit D of the customer's CHWM contract. See Documentation Tables 3.15 and 3.16 for an example of application of both the default DFS capacity charge and a DFS capacity charge that has been capped by the annual test. Documentation Table 3.23 shows the individual DFS capacity charges that are calculated for the individual resources to which DFS is applied.

**3.1.13.2.3 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 resource transmission schedules if the resource requires an e-Tag. For wind resources within the BPA Balancing Authority Area, transmission curtailments associated with Dispatcher Standing Order (DSO) 216 will be treated as lowered scheduled amounts when calculating the actual generation for such a resource.

**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. Table 3.23 of the Documentation shows the DFS energy rates that are calculated for the individual resources to which DFS is applied. GRSP II.P.1.(b) includes the formula for calculating the DFS energy charges for the individual resources to which DFS is applied.

#### 3.1.13.2.4 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 is flat across the year, on a planned basis.

**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 multiplying the Resource Shaping rate by the Resource Shaping billing determinant. The sum of the values is divided by 24 (or 12 if the service applies only in FY 2013) to calculate a flat monthly charge. 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. Example calculations for a solar resource and a wind resource are included in Documentation Tables 3.18 and 3.22. Table 3.23 of the Documentation shows the Resource Shaping charges that are calculated for the individual resources to which DFS is applied. GRSP II.P.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.

#### 3.1.13.2.5 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 wind resources within the BPA Balancing Authority Area, transmission curtailments associated with DSO 216 will be treated as lowered scheduled amounts when calculating the actual generation for such a resource. **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 charge 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.P.1.(d) includes the formula for calculating the Resource Shaping Charge Adjustment for the individual resources to which DFS is applied.

**3.1.13.2.6 DFS and Resource Shaping Charge Application to Tier 1 Augmentation**

The TRM states that RSS pricing will be used to make certain Federal resource acquisitions financially equivalent to a flat block. TRM, section 8. In addition, Tier 1 Augmentation is assumed to be in the shape of an annual flat block purchase for ratemaking purposes. TRM, section 3.5. 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 3.23 shows the summary DFS, Resource Shaping, and TSS charges that are calculated for Klondike III.

#### 3.1.13.3 RSS Secondary Crediting Service (SCS)

SCS provides a credit to a Load Following customer that dedicates to its load the entire output of a hydroelectric Existing Resource for the energy produced by that resource that is in excess of the monthly/diurnal amounts specified in the CHWM Contract Exhibit A or a charge for any energy shortfall by the resource from the monthly/diurnal Exhibit A amounts. If a customer does not take this service, it must apply the exact Exhibit A amounts to its load.

Credits are provided to the customer when its resource generates more than the contract amount. This 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. Likewise, when generation is less than the contract amounts, the customer is charged, because BPA's secondary revenues would be lower or BPA's balancing costs would be higher. The unanticipated credit or cost BPA would experience is passed through to the customer by the SCS, using the posted Resource Shaping rate as the market rate. The PF-12 rate schedule includes a section on the rate application of the SCS-related charges. The GRSPs include the formulas for calculating the SCS charges for the resources to which SCS is applied. GRSP II.P.2. Documentation Table 3.23 includes the individual SCS Administrative Charges for the individual non-Federal resources to which SCS is applied.

##### 3.1.13.3.1 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:

- A 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.

**3.1.13.3.2 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 1only (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.13. 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.P.2.(a) includes the formula for calculating the SCS Shortfall Energy Charges/Secondary Energy Credits for the individual resources to which SCS is applied.

#### 3.1.13.3.3 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 below in section 3.5.1.

**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 3.23 shows the SCS Administrative charges that are calculated for the individual resources to which SCS is applied. GRSP II.P.2.(b) includes the formula for calculating the SCS Administrative Charge for the individual resources to which SCS is applied.

### 3.1.13.4 Additional PFp RSS Considerations

#### 3.1.13.4.1 Forced Outage Rating

All generally recognized types of generating resources have 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 five percent forced outage rating for hydroelectric resources, seven percent for thermal resources, and ten 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 seven percent.

#### 3.1.13.4.2 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 amounts produce lower RSS rates and charges. This adjustment applies to both RSS provided under the PF rate schedule, discussed above, and the FPS rate schedule, described below.

#### 3.1.13.4.3 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 Resource Shaping Charge will be credited to the appropriate PFp Tier 1 Customer Rate cost pools. The forecast revenue from the Resource Shaping Charge sales is a revenue credit 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.

## 3.2 Priority Firm Exchange Rate Design

The PF Exchange rate applies to participants in the Residential Exchange Program for sales of exchange energy pursuant to a Residential Sale and Purchase Agreement (RPSA) or a REP Settlement Implementation Agreement (REPSIA). Under either an RPSA or REPSIA, the PF Exchange 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 small 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 PF Exchange rate also applies to any actual power sales to exchanging utilities under contractual "in-lieu" provisions.

The PF Exchange rate is comprised of two components: two common Base PF Exchange rates (one for COUs with CHWM contracts and another for all other participants), and utility-specific REP Surcharges. Neither component of the PF Exchange 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 PF Exchange 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 and, therefore, 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 divided 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 section 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.  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 73 surcharge to determine its utility-specific PFx rate.  For each month of the rate period, the participant will submit to BPA its exchange load 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.

## 3.3 Industrial Firm Power (IP) Rate Design

The rate design for the IP rate consists of 24 monthly/diurnal Energy rates and 12 Demand rates (one for each month).

### 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 section 3.1.12).

IP energy rates are determined by adjusting the PFp Melded rates by the Value of Reserves (VOR) provided by the DSI load, the net industrial margin, and the REP.  See Documentation Table 2.5.7.3.

#### 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.  The FY 2012-2013 rate period DSI power sales forecast is 340.5aMW.

See Power Loads and Resources Study, section 2.4. Based on provisions of DSI contracts currently in place, these power sales are assumed to provide interruption reserve rights to BPA.

The first step for valuing interruption 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 Operating Reserves documented in the Generation Inputs Study are provided by the FCRPS and are available for any hour and on any day.

The second step in valuing the DSI reserves is to determine the quantity of reserves provided. To calculate this quantity, the load of aluminum DSIs available for interruption is reduced to account for wheel-turning load that cannot be curtailed. The wheel-turning load for aluminum DSIs is forecast to be 6 aMW. No wheel-turning amount is established for Port Townsend. The interruption reserves provided are 10 percent of the remaining DSI load. The VOR credit included in the IP-12 rate is 0.94 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 section 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-12 rate is 0.685 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 section 1.2.2. The cost of rate protection allocated to the IP rate is determined pursuant to the 2012 REP Settlement and is included in the IP-12 rate. The IP-12 REP Surcharge is 7.72 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, as described in section 3.1.6.3.

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 will be equal to the 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 kW) that is subtracted from the hourly peak schedule amount when calculating the IP Demand billing determinant. Power Rate Schedules, BP-12-A-02B, *e.g.*, section 2.2.2

## 3.4 New Resources (NR) Rate Design

The rate design for the NR rate consists of 24 monthly/diurnal Energy rates (one each for HLH and LLH for each month) and 12 Demand rates (one for each month).

### 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 2.5.7.4.

The NR energy rates are determined by adjusting the PFp Load Shaping rates by an equal scalar until the NR energy rates recover the allocated NR revenue requirement minus the forecast Demand charge revenue. See Documentation Table 2.5.7.4.

After the scaling process is complete, an 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 section 1.2.2. The cost of rate protection allocated to the NR rate is determined pursuant to the 2012 REP Settlement. The NR-12 REP Surcharge is 7.72 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, as described in section 3.1.6.3.

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.

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

Products and services available under this rate schedule are described in BPA's 2012 Power Rate Schedules, BP-12-A-02B. 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-12 rate schedule may be sold at market-based or negotiated rates, which may have a demand component, an energy component, or both. Applicable transmission rates will apply to the extent required to purchases of firm power under the FPS-12 rate.

The FPS rate schedule provides for seven products and services: (1) Firm Power and Capacity Without Energy; (2) Supplemental Control Area Services; (3) Shaping Services; (4) Reservations and Rights to Change Services; (5) Reassignment or Remarketing of Surplus Transmission Capacity; (6) Services for Non-Federal Resources; and (7) Unanticipated Load Service.

#### 3.5.1 Firm Power and Capacity Without Energy

When available, BPA sells firm power, including secondary energy, or firm capacity for use within the Pacific Northwest and outside of 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 made by BPA at the time of the sale, as set forth in the 2010 REP Settlement Agreement.

#### 3.5.2 Supplemental Control Area Services

BPA sells supplemental control area services, when available, for use within the Pacific Northwest and outside of 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 Shaping Services

BPA sells shaping services, when available, for use within the Pacific Northwest and outside of 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 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 the Pacific Northwest and outside of 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 Reassignment or Remarketing of Surplus Transmission Capacity

BPA reassigns or remarkets its surplus transmission capacity, when available, that has been purchased from a transmission provider, including Transmission Services, consistent with the terms of the transmission provider's Open Access Transmission Tariff. BPA sells this surplus transmission capacity to parties within the Pacific Northwest and outside of 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.

### 3.5.6 Services for Non-Federal Resources

For the first time, BPA is offering Forced Outage Reserve Service (FORS) and Transmission Scheduling Service (TSS) at posted FPS rates. FORS is one of the Resource Support Services and is offered under the FPS rate schedule to customers with resources that meet specific requirements specified in the CHWM contract. FORS for customers without CHWM contracts would be offered, if available, under the Reservations and Rights to Change Services part of the FPS rate schedule. TSS is not an RSS but is related to the services that comprise RSS. It is a required service for customers with resources that meet eligibility requirements specified in the

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

The FPS rate schedule includes a section on the general rate application of the FORS- and TSS-related charges. The GRSPs include the formulas for calculating the FORS Capacity and Energy Charges and TSS and TCMS Charges for the resources to which FORS or TSS/TMCS is applied.

#### 3.5.6.1 Forced Outage Reserve Service

FORS is an optional service to provide an agreed-upon amount of capacity and energy to customers with a qualifying resource that experiences a forced outage. This service can be considered to be 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.

##### 3.5.6.1.1 FORS Pricing Summary

The charges for FORS are intended to reflect the cost of (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.

**3.5.6.1.2 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.P.3.(a)(1).

**FORS Capacity Billing Determinant.** For each resource, the 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 section 3.1.13.2.2. The forced outage rating for a resource taking FORS has the same considerations as described in section 3.1.13.4.1.

**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 will be specified in section 2.4.5.3 of Exhibit D of the CHWM contract. A wood waste resource example in Table 3.20 of Documentation shows the calculation of the FORS Capacity charge. Table 3.23 of Documentation show 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.P.3.(a)(2).

#### 3.5.6.1.3 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.P.3.(b) shows the formula for calculating the FORS energy charges for the individual resources to which FORS is applied.

### 3.5.6.2 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.

#### 3.5.6.2.1 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 contract 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 2012 and FY 2013 for

- 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 after-the-fact TCMS charge based on replacement power or transmission costs caused by a transmission event.

**3.5.6.2.2 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 2009 and FY 2010. See Documentation Table 3.7.

**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 FY 2013 if this service applies in only FY 2013). The sum of the monthly values is divided by 24 (or 12 if the service applies in only FY 2013) to calculate a flat monthly charge.

The TSS charge is subject to a cap such that if the annual cost to the customer using the TSS rate exceeds $1,080/month, then the monthly charge is capped at $1,080/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 2009 and FY 2010.

Examples for a wind resource and a biomass resource show how the TSS charge described above is calculated. See Documentation Tables 3.20 and 3.22. Table 3.23 of the Documentation 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.P.4.(a)(3) shows the formula for calculating the TSS charge for the individual resources to which TSS is applied.

#### 3.5.6.2.3 TCMS Charge

A TCMS rate 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.P.4.(b)(3) shows the formula for calculating the TCMS charges for the individual resources to which TCMS is applied.

For the BP-12 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.

#### 3.5.6.3 TSS Charge Application to Tier 1 Augmentation

The TRM states that RSS pricing will be used to make Federal resource acquisitions financially equivalent to a flat block.  TRM section 8.  In addition, Tier 1 Augmentation is assumed for ratemaking purposes to be in the shape of an annual flat block purchase.  TRM section 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.  This 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.

#### 3.5.6.4 Credits to the PFp Tier 1 Customer Rate Cost Pools

Forecast revenue credits are calculated from the RSS charges. All revenues, except those from the Resource Shaping Charge, are allocated as credits to the Composite Customer cost pools. The forecast revenue from the Resource Shaping Charge is allocated as a credit to the Non-Slice Customer cost pool. Additional information on these revenue credits is found in sections 3.1.2.1 and 3.1.2.2.

### 3.5.7 Unanticipated Load Service (ULS)

Under the FPS-12 rate schedule, the Resource Replacement (RR) rate will be applied to Unanticipated Load Service for delays in the on-line 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 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 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. The ULS under the FPS-12 rate schedule is specified in GRSP II.U.4.

## 3.6 General Transfer Agreement Service Rate Design

Transfer Services are the transmission and distribution services BPA acquires from other transmission providers to transmit Federal power to BPA customers located within third-party-owned transmission systems. Transfer Service customers may be subject to one or two separate charges from BPA under the General Transfer Agreement Service (GTA-12) rate: (1) the General Transfer Agreement (GTA) Delivery Charge, and (2) the Transfer Service Operating Reserve Charge. 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 (GRSP I.E.).

**3.6.1 GTA Delivery Charge**

The GTA Delivery Charge, section I of the GTA-12 rate schedule, is a rate 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 when BPA is paying for the transfer service over the third-party transmission system, unless such costs have been directly assigned to the specific customer.

Since 2002, the GTA Delivery Charge has mirrored the Transmission Services Utility Delivery Charge. For the FY 2010-2011 rate period, the Transmission Services Utility Delivery rate was set at $1.119 per kilowatt per month; GTA-10 was consistent with that rate. Power Services is continuing the application of the $1.119 per kilowatt per month rate and billing factor for the GTA-12 Delivery Charge.

The GTA Delivery Charge revenue forecast is approximately $2.5 million per year, as shown in Table 4.11 of Documentation. This revenue forecast was derived by applying the GTA Delivery Charge of $1.119 per kilowatt per month to the forecast peak loads at the points of delivery at which customers currently pay the GTA Delivery Charge.

### 3.6.2 Transfer Service Operating Reserve Charge

The Transfer Service Operating Reserve Charge is designed to address a potential change in Operating Reserve obligations. Currently, BPA does not pay Operating Reserves on third-party systems for the transmission of Federal power to Transfer Service customers because Transfer Service customers already pay the required Operating Reserve transmission charge. The Western Electricity Coordinating Council (WECC) has proposed a change to this requirement that would reduce the Operating Reserve obligation of the BPA balancing authority area for Transfer Service customers and shift a portion of the obligation to the balancing authority areas where the Transfer Service Customer conducts business. This change, if adopted, would shift a portion of the costs for Operating Reserves from Transfer Service customers to BPA.

In anticipation of this potential change, the Transfer Service Operating Reserve Charge for the FY 2012-2013 rate period is designed to mitigate the cost shift described above in the event the Commission adopts WECC's proposed change. The Transfer Service Operating Reserve Charge rate, if assessed, would be the same as the ACS-12 rate for Operating Reserves that Transmission Services charges to customers that have load in the BPA balancing authority area.

Due to the uncertain nature of if and when WECC's proposed changes may be adopted by the Commission and implemented by the various transmission providers, the implementation of the Transfer Service Operating Reserve Charge has been conditioned upon the satisfaction of three criteria: (1) BPA serves the power customer by Transfer Service; (2) the Transfer Service customer does not pay Transmission Services for Operating Reserves based on 3 percent of the customer's load; and (3) BPA is assessed Operating Reserve charges from a third-party transmission provider to transfer Federal power to the power customer's load. Power Services intends to assess the Transfer Service Operating Reserve Charge only if all three criteria have been satisfied.

The forecast revenue associated with the Transfer Service Operating Reserve Charge is zero, because implementation of the Transfer Service Operating Reserve Charge will generally result in no net revenue impact.  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 systems.

# 4. REVENUE FORECAST

The revenue forecast calculates the expected level of revenue from power rates and other sources for the rate period, FY 2012-2013, as well as the current year, FY 2011. Two revenue forecasts are prepared. The first uses rates from the rate schedules currently in effect, and the second uses proposed rates. The revenue forecasts are used to test whether current rates and proposed rates will recover the power revenue requirement. Upon showing that revenues at current rates will not generate sufficient revenue to recover the power revenue requirement, a rate change is necessary, and revenues at proposed rates are generated. See Power Revenue Requirement Study, sections 3.2 and 3.3. Both forecasts are based on the Power Loads and Resources Study 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 PFp revenues and IP revenues. All other revenues remain constant between the two forecasts.

In addition to forecasts of revenues, this study calculates power purchase expenses that are directly related to generation levels of surplus energy. Power purchases are included in the forecast for FY 2011-2013 and discussed in section 4.5.

Also included in the revenue forecast are revenue calculations for the current year, FY 2011. This forecast is needed to estimate the amount of financial reserves available to BPA at the beginning of the rate period. See Power Revenue Requirement Study, section 1.1.

The revenue forecast is divided into four main categories: (1) gross sales, described in section 4.1; (2) miscellaneous revenues, described in section 4.2; (3) generation inputs for ancillary, control area, and other services, described in section 4.3; and (4) Treasury credits, described in section 4.4. The change in organization from the WP-10 revenue forecast is designed to increase consistency with other BPA financial documents in terms of revenue categories. In addition, there are multiple new revenue categories compared to the WP-10 revenue forecast.

### 4.1 Revenue Forecast for Gross Sales

Gross Sales are the largest source of revenue for Power Services. There are eight sources of revenue in this category: firm power sales under the Subscription and CHWM contracts, described in section 4.1.1; Industrial Firm Power sales to DSIs, described in section 4.1.2; pre-Subscription contract sales, described in section 4.1.3; short-term market sales, described in section 4.1.4; long-term contractual obligations, described in section 4.1.5; Canadian entitlement returns, described in section 4.1.6; Renewable Energy Certificates, described in section 4.1.7; and other sales, described in section 4.1.8.

#### 4.1.1 Firm Power Sales under Subscription and CHWM Contracts

For FY 2011, the revenues from Priority Firm power sales pursuant to Subscription contracts are calculated under the WP-10 rate structure, and revenues are reported for HLH energy, LLH energy, demand, load variance, and irrigation mitigation, as applicable. Additional details about this rate structure can be found in the 2010 Wholesale Power Rate Schedules, WP-10-A-02, Appendix B. Subscription revenues for FY 2011 are listed in Table 2, lines 3 – 9 and in Documentation Table 4.1, lines 3 – 9.

For FY 2012-2013, revenues from PF power 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 RAM2012. Revenue forecasting inputs and results are managed and calculated pursuant to the CHWM contracts using a database referred to as the Revenue Forecasting

Application (RFA). Revenues are reported for Tier 1 Composite (Slice and Non-Slice), Load Shaping, and Demand (including the Low Density Discount and Irrigation Rate Discount credits), and any additional Tier 2 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. Revenues obtained from the Composite and Non-Slice Customer charges represent the majority of revenues from firm power sales under CHWM contracts. Composite and Non-Slice revenues for FY 2012-2013 are listed in Table 3, lines 4 – 5, and Documentation Table 4.2, lines 10 – 11.

#### 4.1.1.2 Load Shaping Charge

The Load Shaping charge is designed to reflect the costs and benefits of shaping the Tier 1 System Capability to the monthly/diurnal shape of a customer's Below-HWM load. A charge to the customer results when the customer's shaped load is greater than its share of the Tier 1 System Output; the customer will receive a credit from BPA when the opposite occurs. The Load Shaping charge is described in detail in section 3.1.6.2, and an example calculation of the Load Shaping charge is available in Documentation Table 4.6. Load Shaping revenues for FY 2012-2013 are listed in Table 3, line 7, and Documentation Table 4.2, line 13.

#### 4.1.1.3 Demand Charge

The Demand charge is applicable to customers purchasing Load Following or Block with Shaping Capacity products. 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, CDQ, and Super Peak Credit (if applicable). Calculation of a customer's Demand charge is described in section 3.1.6.3, and an example calculation is available in Documentation Table 4.6. Demand revenues for FY 2012-2013 are listed in Table 3, line 8, and in Documentation Table 4.2, line 14.

#### 4.1.1.4 Irrigation Rate Discount

The IRD is a rate credit to eligible customers and provides a fixed rate discount on Tier 1 rates. Eligible irrigation loads during May, June, July, August, and September are identified in each customer's CHWM contract, and the irrigation load amount will not increase during the contract term. The discount does not apply to loads served at Tier 2 rates. A methodology for calculating an end-of-year true-up appears in GRSP II.H.2. Forecast credits for irrigation loads will be calculated using an IRD that is derived by multiplying the irrigation loads identified in the CHWM contracts multiplied by the IRD rate. The IRD is described in section 3.1.11, and an example calculation is available in Documentation Table 4.7. IRD credits for FY 2012-2013 are listed in Table 3, line 9, and Documentation Table 4.2, line 15.

#### 4.1.1.5 Low Density Discount

The LDD is a credit to certain customers, generally in rural areas, to avoid adverse rate impacts to customers with low system densities. The LDD principles, eligibility criteria, and discount appear in GRSP II.J. Under the TRM, LDD percentages are adjusted to provide a discount on purchases at Tier 1 rates that approximates the discount the customer would receive under non-tiered rates. An example calculation is available in Documentation Table 4.8. LDD credits for FY 2012-2013 are listed in Table 3, line 10, and in Documentation Table 4.2, line 16.

#### 4.1.1.6 Tier 2 and Resource Support Services

Tier 2 rates are based on a cost allocation that fully 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 2012-2013 are listed in Table 3, line 11, and Documentation Table 4.2, line 17.

RSS allows a customer to apply the variable output of a resource to serve its Above-RHWM load without having to guarantee a specific scheduled shape of this resource. These services are available for all specified non-Federal resources that Load Following customers contractually dedicate to serve their total retail load and for specified new renewable resources that Slice/Block customers contractually dedicate to serve their total retail load. Revenues from these services are based on known services chosen by customers. Revenues for FY 2012-2013 are listed in Table 3, line 12, and Documentation Table 4.2, line 18.

#### 4.1.2 Industrial 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 340.5aMW for FY 2011-2013, documented in the Power Loads and Resources Study and accompanying Documentation; and (2) the appropriate IP rate from RAM2012. For FY 2011, the revenues for DSI customers are calculated using the WP-10 IP rate. Revenues for FY 2011-2013 are listed in Table 3, line 14, and Documentation Table 4.2, line 20.

#### 4.1.3 Pre-Subscription Sales

BPA provides power to certain customers under pre-Subscription contracts. During FY 2011, there are eleven pre-Subscription contracts, and during FY 2012-2013, there is one. The revenues from pre-Subscription customers are derived by multiplying individual customer loads by the appropriate FPS rate, both of which are set pursuant to the pre-Subscription contracts. Revenues for FY 2011-2013 are listed in Table 3, line 15, and Documentation Table 4.2, line 21.

### 4.1.4 Short-Term Market Sales

The revenue forecast includes revenues from the sales of surplus energy, which is energy in excess of that required to serve firm loads. For rate development purposes, the forecast of firm FCRPS output is based upon critical (1937) water conditions. FCRPS output, while uncertain, is expected to be greater than under 1937 water conditions, and thus surplus energy sales and revenue result. For FY 2011, 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 RiskMod simulations of 50 games for each of 70 historical water years, for a total of 3,500 games. For FY 2012-2013, the surplus energy revenue is the median of the surplus energy revenues across 3,500 games. In both cases, this power is sold under the FPS rate schedule.

The revenue forecast for short-term market sales is computed using RiskMod to calculate monthly HLH and LLH energy surpluses for each of the 3,500 games, applying corresponding market prices developed for each game. See Power Risk and Market Price Study, section 2.6.3, and Documentation Table 21. Revenues for FY 2011 – 2013 are shown in Table 3, line 16, and Documentation Table 4.2, line 22.

### 4.1.5 Long-Term Contractual Obligations

Long-term obligation contracts include the WNP-3 Exchange Settlements, a wind energy exchange, capacity and energy exchanges, and a seasonal power exchange. For FY 2011-2013, 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 capacity and energy exchanges, as well as the seasonal power exchange, do not generate revenue. Revenue for FY 2011-2013 is listed in Table 3, line 17, and Documentation Table 4.2, line 23.

#### 4.1.6 Canadian Entitlement Return

The Canadian Entitlement Return is an obligation for BPA to deliver power to Canada at the border. 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 2011-2013 are listed in Table 3, line 18, and Documentation Table 4.2, line 24.

#### 4.1.7 Renewable Energy Certificates

RECs are the environmental attributes corresponding to one megawatthour of generation from a renewable energy resource. BPA sells a portion of the RECs it receives as part of its energy purchases from six wind projects. Under Subscription contracts, 43 preference customers have rights to purchase RECs through FY 2016. BPA forecasts that these preference customers will exercise their full rights up to the limits set in the Subscription contracts; this forecast quantity is about 40 aMW. The price for the RECs for FY 2012-2013 was set outside this rate proceeding pursuant to the terms of the contracts. BPA established the REC price as $7.50 for FY 2012 and $8.00 for FY 2013 in May 2011. After eligible preference customers have exercised their contract REC purchase rights, the RECs remaining in BPA's inventory for FY 2012-2013 will be distributed on a pro-rata basis to all CHWM customers based on customers' RHWMs. These RECs are distributed at no additional charge to the customers and do not generate any revenue for Power Services. Revenues for RECs in FY 2012-2013 are listed in Table 3, line 19, and Documentation Table 4.2, line 25.

#### 4.1.8 Other Sales

Other sales include revenues from Network Wind Integration Service and from the Storage and Shaping Service, which shapes the variable output for a preference customer's share of a wind project. For FY 2011, 2012, and 2013, the rates for both of these services are set in the respective contracts, then adjusted each fiscal year for inflation. The amount of capacity used as the billing factor for these services is also set in the contracts but remains constant over the length of the contract. Other sales also include miscellaneous revenues from transfer customers and forecast revenues from the Slice True-Up, which is applicable only for FY 2011. Other sales revenue for FY 2011-2013 is listed in Table 3, line 20, and Documentation Table 4.2, lines 26 – 29.

### 4.2 Revenue Forecast for Miscellaneous Revenues

Miscellaneous Revenues include revenues from Energy Efficiency, Downstream Benefits, U.S. Bureau of Reclamation (Reclamation) power for irrigation, and the Upper Baker project. Energy Efficiency revenues are received by BPA as reimbursements for costs relating to implementation of various energy efficiency projects. For FY 2011-2013, revenues from Energy Efficiency are calculated by estimating project expenditures. These revenues are wholly offset by the associated expenditures, which are recorded on the expense ledger.

Downstream Benefits are revenues BPA receives from utilities that benefit from the coordinated planning and operation of U.S. Army Corps of Engineers and Reclamation upstream storage reservoirs as part of the Pacific Northwest Coordination Agreement. For FY 2011-2013, revenues from downstream benefits are calculated by applying a forecast of the operations and maintenance costs adjusted for inflation to the energy amounts from the most recent study conducted by the Northwest Power Pool (NWPP). The NWPP conducts a study each year on behalf of the utilities to calculate the energy amounts used in determining the downstream benefits.

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 to Reclamation irrigation projects is classified as either “Reserved Power” or “Irrigation Pumping Power.” Revenue from Reserved Power for FY 2011, 2012, and 2013 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 2011, 2012, and 2013 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 requires it to be held at a lower level during the winter than it would be without flood control, and this creates head losses. On behalf of the Army Corps of Engineers, 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 from the Corps of Engineers.

Miscellaneous revenues for FY 2011-2013 are listed in Table 3, line 22, and Documentation Table 4.2, lines 31 – 36.

### 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. This revenue forecast includes generation inputs for Regulating Reserve, Variable Energy Resource Balancing Service (VERBS) Reserve, Dispatchable Energy Resource Balancing Service (DERBS) Reserve, and Operating Reserves. Power Services receives revenue from Transmission Services for providing generation inputs for other services, including Synchronous Condensing, Generation Dropping, Energy Imbalance, and Generation Imbalance. Other inter-business line allocations revenues include Redispatch, Segmentation of USACE and Reclamation network and delivery facilities costs, and station service. All these generation inputs are explained in the Generation Inputs Study, BP-12-FS-

BPA-05. Revenues are listed in PRS Table 3, line 23, and Documentation Table 4.2, lines 37 – 50.

## 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

Section 4(h)(10)(C) of the Northwest Power Act states that the amounts BPA spends for protecting, enhancing, and mitigating fish and wildlife in the region shall be allocated among the FCRPS hydro projects based on the various project purposes. BPA pays the entirety of the costs relating to the obligations of section 4(h)(10)(C) and is reimbursed by the U.S. Treasury for 22.3 percent of the total 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. This credit is treated as Power Services revenue.

Program and capital expenses relating to the fish and wildlife programs are discussed in the Power Revenue Requirement Study. The methodology for estimating the replacement power purchases resulting from changes in hydro system operations to benefit fish and wildlife is described in section 3.3.1 of the Power Loads and Resources Study. The cost of the increased purchases is estimated using RiskMod and the market price forecast and is included in the Power Risk and Market Price Study, section 2.6.1, and Documentation Table 16. Revenue from 4(h)(10)(C) credits is listed in PRS Table 3, line 24, and Documentation Table 4.2, line 52.

### 4.4.2 Colville Settlement Credits

The Colville Settlement Act Credits are discussed in section 1.2.3 of the Power Revenue Requirement Study. 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 2012 and FY 2013 is set by legislation at $4.6 million per year [Public Law No. 103-436; 108 Stat. 4577, as amended] and is listed in Table 3, 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 in the rate case. Therefore, they are included in the Power Services revenue forecast.

### 4.5.1 Augmentation Purchase Expense

As explained in section 3.1.2.1.3 of the Power Loads and Resources Study, the forecast of firm FCRPS output is based upon critical (1937) water conditions. The forecast annual firm FCRPS output plus 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 Loads and Resources Study projects the need to acquire system augmentation of 176 aMW in FY 2013 to meet firm loads. No augmentation is projected to be necessary for FY 2012. See Power Load and Resources Study, section 4.2.

In addition, BPA is purchasing Excess Requirements Energy (ERE) from two Slice customers in the amount of 10.7 aMW in FY 2011. ERE is an amount of requirements power that is determined to be in excess of a Slice customer's Net Requirement. Pursuant to Exhibit N of the Subscription Block and Slice Power Sales Agreement and any related Exhibit N Settlement Agreement, BPA has the right to purchase ERE from Slice customers under certain conditions. The ERE amounts are deducted from the aggregate augmentation amounts to determine the augmentation amount used in this Study. Due to expiration of Subscription contracts effective in FY 2012, ERE augmentation will no longer be available to BPA after FY 2011.

The expense for the augmentation amounts of 0 aMW in FY 2012 and 176 aMW in FY 2013 is based on projected prices using the AURORAxmp model assuming critical water conditions. See Power Risk and Market Price Study, section 2.6.2, and Documentation Table 17. These prices and the corresponding cost of these augmentation purchases also are documented in Documentation Table 17. Augmentation purchase amounts for FY 2011-2013 are listed in Table 3, line 27, and Documentation, Table 4.2, lines 55 – 57.

### 4.5.2 Balancing Power Purchases

Balancing power purchases are calculated by RiskMod, which finds any monthly HLH and LLH energy deficits by simulations of 50 games in each of the 70 water years, for a total of 3,500 games, and applying the corresponding market prices developed for each game. Similar to the treatment of short-term market sales, the mean value for balancing purchases over the 3,500 games is reported for FY 2011 for forecast months, added to actual purchases in past months, and the median value is reported for FY 2012-2013. Total balancing purchase expense for FY 2011-2013 is listed in PRS Table 3, line 28, and Documentation Table 4.2, line 58. A full description is available in the Power Risk and Market Price Study, section 2.6.3, and Power Risk and Market Price Study Documentation Table 22.

### 4.5.3 Other Power Purchases

The majority of other power purchases is from committed winter hedging purchases BPA has made to cover forecast HLH energy deficits during winter months under many water conditions. In those months and water years where firm loads exceed resources, these winter hedging purchases reduce balancing purchases. Conversely, in those months and water years where resources are sufficient to serve firm loads, these winter hedging purchases increase the amount of surplus sales. RiskMod accounts for the energy relating to winter hedging purchases in the balancing purchases category. However, the amount of expense is included separately. The reporting of hedging contracts differs from that of the WP-10 revenue forecast, where both expense and energy were included in balancing purchase expense. The reason for this reporting change is that these purchases are contractual obligations and are viewed as committed purchases in the context of the revenue forecast.

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 2011-2013 is listed in Table 3, line 29, and Documentation Table 4.2, line 59.

## 4.6 Summary Table of Power Revenues

A detailed table of power revenues is available in Tables 2 and 3 and in Documentation Tables 4.1 and 4.2.

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# 5. RATE SCHEDULES

The 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 GRSPs that apply to each rate schedule. The Power rate schedules described in this section are presented in their entirety in BP-12-A-02B.

## 5.1 Priority Firm Power Rate, PF-12

The PF-12 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 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.

### 5.1.1 Firm Requirements Power under a CHWM Contract

Rates for firm requirements purchases under a CHWM contract include Tier 1 rates, Tier 2 rates, Resource Support Services rates, and the Unanticipated Load rate. The Tier 1 rates are comprised of the three Customer charge rates (Composite, Non-Slice, Slice), Demand rates, and Load Shaping rates. Tier 2 rates include the Short-Term and Load Growth rates. Resource Support Services rates are provided for Diurnal Flattening Service, Resource Shaping, and Secondary Crediting Service. Unanticipated Load rates are applicable to requests for firm requirements service to unanticipated load.

### 5.1.2 Firm Requirements Power under a Contract other than a CHWM Contract (the Melded Rate Option)

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

### 5.1.3 PF Exchange Rate

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-12

The NR-12 rate is applicable to sales to investor-owned utilities under Northwest Power Act section 5(b) requirements contracts. The NR-12 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-12 rate includes energy and demand rates. The NR-12 rate schedule also includes the Unanticipated Load rate.

## 5.3 Industrial Firm Power Rate, IP-12

The IP-12 rate schedule is available for firm power sales to DSIs, as defined by the Northwest Power Act, pursuant to section 5(d). The IP-12 rate includes energy and demand rates. DSIs purchasing power pursuant to the IP-12 rate schedule shall be required to provide the Minimum DSI Operating Reserve – Supplemental.

## 5.4 Firm Power Products and Services Rate, FPS-12

The FPS-12 rate schedule is available for the purchase of Firm Power, Capacity Without Energy, Supplemental Control Area Services, Shaping Services, Reservation and Rights to Change

Services, Reassignment or Remarketing of Surplus Transmission Capacity, Transmission Scheduling Service/Transmission Curtailment Management Service, Forced Outage Reserve Service, and Unanticipated Load Service under the Resource Replacement rate. Rates and billing determinants for the products and services sold under the FPS rate schedule are either specified by BPA or mutually agreed by BPA and the customer.

### 5.5 General Transfer Service Agreement Rate, GTA-12

The GTA-12 rate schedule includes the GTA Delivery Charge and the Transfer Service Operating Reserve Charge applicable to customers served under a general transfer agreement.

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# 6. GENERAL RATE SCHEDULE PROVISIONS

The GRSPs describe the adjustments, charges, and special rate provisions applicable to the various 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 BP-12-A-02B.

## 6.1 Supplemental Direct Assignment Guidelines

The Supplemental Direct Assignment Guidelines address how BPA will recover the costs for facility expansions and upgrades on third-party transmission systems for transfer service customers. The Supplemental Direct Assignment Guidelines, in conjunction with the Transmission Services Guidelines for Direct Assignment Facilities, as described in the Transmission Services Business Practices, 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 2012-2013 rate period. See GRSP II.A.

## 6.3 Cost Contributions

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

## 6.4 Cost Recovery Adjustment Clause (CRAC)

The CRAC is an upward rate adjustment mechanism that can respond to the financial risks BPA faces before BPA has another chance to set rates during a full rate case. 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, section 3.2.4.

## 6.5 Dividend Distribution Clause (DDC)

The DDC is a downward rate adjustment mechanism that returns 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.D and Power Risk and Market Price Study, section 3.2.5.

## 6.6 DSI Reserves Adjustment

In the event that BPA agrees to acquire an additional reserve product from a DSI, this adjustment (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.E.

## 6.7 Flexible New Resource Firm Power Rate Option

The Flexible NR rate option, offered at BPA's discretion, allows NR-12 rates and billing determinants to be modified to accommodate a customer's request to change the way power is charged under the NR-12 rate schedule. The GRSP describes the factors that will be considered in such modifications. See GRSP II.F.

## 6.8 Flexible Priority Firm Power Rate Option

The Flexible PF rate option, offered at BPA's discretion, allows PF-12 rates and billing determinants to be modified to accommodate a customer's request to change the way power is charged under the PF-12 rate schedule. The GRSP describes the factors that will be considered in such modifications. See GRSP II.G.

## 6.9 The NFB Mechanisms

There are two NFB mechanisms that 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.K and Power Risk and Market Price Study, section 4.2.

## 6.10 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.L.

### 6.11 REP 7(b)(3) Surcharge Adjustment

The Residential Exchange Program 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 Average System Cost (ASC) and forecast exchange loads of all utilities assumed in ratemaking to participate in the Residential Exchange Program. Each REP participant's initial 7(b)(3) surcharge is displayed in section 6.1 of the PF-12 rate schedule. Each 7(b)(3) surcharge is subject to change during the rate period if a participant's ASC during the rate period due to the addition or removal of a resource from a 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 this GRSP. See GRSP II.O for the procedures.

### 6.12 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-12 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.T.

### 6.13 Unanticipated Load Service

Unanticipated Load Service (ULS) applies to any request for Firm Requirements Power received after February 1, 2011, that results in an unanticipated increase in a customer's load placed on BPA during the FY 2012-2013 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 from under retail access. See GRSP II.U.

## 6.14 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 charge is 1.25 times the applicable monthly demand charge. The UAI energy charge is the greater of 150 mills/kWh or 2.0 times the highest hourly Powerdex Mid-C Index price for firm power for the month. See GRSP II.V.

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# 7. SLICE

## 7.1 Slice True-Up Adjustment

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

## 7.2 Composite Cost Pool True-Up

The Composite Cost Pool True-Up refers to the calculation of the annual Slice True-Up Adjustment for the Composite cost pool. For each Slice customer, the annual Slice True-Up Adjustment Charge for the Composite cost pool will be calculated by:

(1) subtracting:

- (i) the forecast annual expenses, revenue credits, and adjustments allocated to the Composite Cost Pool for the applicable fiscal year of the rate period from
- (ii) the actual expenses, revenue credits, and adjustments in the applicable fiscal year of the rate period that are allocable to the Composite cost pool;

(2) dividing the difference determined in (1) above by the sum of the actual Composite cost pool TOCAs for that fiscal year (TOCAs are determined in accordance with TRM section 5.1.1 based on the Annual Net Requirement for Slice customers and computed consistent with the Load Shaping True-Up methodology set forth in TRM section 5.2.4.1 for Load Following customers); and

(3) multiplying the quotient by each Slice customer's Slice Percentage for the applicable fiscal year.

As part of the Composite Cost Pool True-Up, the Firm Surplus and Secondary Adjustment from Unused RHWM will be revised to reflect the adjusted TOCAs for each fiscal year as described above in section 1.2 and the resulting revenue difference between a sale at the posted Composite Customer rate and at the rate case-determined value of Unused RHWM. For each Slice customer, the dollar amount calculated, which may be positive or negative, constitutes its Slice True-Up Adjustment charge for the Composite cost pool. See GRSP II.R. for a description of the Composite Pool True-Up and the calculation of the Actual Firm Surplus and Secondary Adjustment from Unused RHWM. Table G of the GRSPs, the Composite Cost Pool True-Up Table, contains the forecast expenses, revenue credits, and adjustments that will be the basis for the Composite Cost Pool True-Up calculation when compared to actual expenses, revenue credits, and adjustments.

## 7.3 Treatment of Certain Expenses, Revenue Credits, and Adjustments in the Composite Cost Pool True-Up

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

### 7.3.1 System Augmentation Expenses

System augmentation expenses are included in the FY 2012-2013 Composite cost pool. Part of these augmentation expenses is 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.

System augmentation expenses will not be 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 implicit in the Composite Cost Pool True-Up for the DSI revenue credit, are adjustments that reflect the effects of additional power purchases (or lack thereof) or additional power sales to the market. See section 3.1.3.2 for a description of 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 purchases 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, the augmentation expense and RSS and RSC costs associated with generation output from the Klondike III resource will not be subject to the Composite Cost Pool True-Up.

#### 7.3.2 Balancing Augmentation Adjustment

The Balancing Augmentation Adjustment can result in a credit to the Composite cost pool or it can result in a negative credit to the Composite cost pool. See section 3.1.3.3 for a description of the Balancing Augmentation Adjustment, the circumstances that would result in a credit, and the circumstances that would result in a negative credit. The Balancing Augmentation Adjustment will not be subject to the Composite Cost Pool True-Up.

#### 7.3.3 Firm Surplus and Secondary Adjustment from Unused RHWM

The Firm Surplus and Secondary Adjustment from Unused RHWM will be subject to the Composite Cost Pool True-Up. The methodology specified in GRSP II.R.1.a. will be used to calculate the actual firm surplus and secondary adjustment from Unused RHWM for purposes of the Composite Cost Pool True-Up. The actual Firm Surplus and Secondary Adjustment from Unused RHWM will be calculated by starting with the rate case forecast for the firm surplus and secondary adjustment and adding dollar amounts to reflect the change in the sum of actual

TOCAs from the sum of forecast TOCAs. The calculation of the actual firm surplus and secondary 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.

The calculation of the actual firm surplus and secondary adjustment reflects the fact that 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.

#### 7.3.4 DSI Revenue Credit

The forecast costs associated with service to the DSIs are included in the Composite cost pool. See TRM section 3.2.1.3. DSI revenues received by BPA are included in the Composite cost pool as credits. The DSI revenue credit will be subject to the Composite Cost Pool True-Up.

For purposes of the Composite Cost Pool True-Up, an actual DSI revenue credit will be calculated. For details on how the actual DSI revenue credit will be calculated, see GRSP II.R.1.(b).

The calculation of the actual DSI revenue credit starts with the forecast DSI revenue credit and makes an adjustment to the forecast to calculate the actual DSI revenue credit. When the 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.

When the 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 will reflect these effects. The adjustment will also include any DSI take-or-pay revenues, if applicable.

#### 7.3.5 Unspent Green Energy Premium Revenues

For ratesetting purposes, a forecast amount of unspent GEP revenue balance remaining at the end of FY 2011 will be applied as a contra-expense in FY 2012-2013 against certain forecast expenses. See 2010 Integrated Program Review Final Close-Out Letter and Report, October 27, 2010. The contra-expense will be subject to the Composite Cost Pool True-Up. The contra-expense included in the Composite cost pool for ratesetting purposes is a forecast of the remaining balance of unspent GEP revenues as of the end of FY 2011. The actual remaining balance of unspent GEP revenues will be calculated after audited actual financial data is available to BPA for FY 2011. The difference between the actual unspent GEP revenues and the forecast of the contra-expense included in the Composite cost pool for ratesetting purposes will be tracked for Composite Cost Pool True-Up purposes. In any given fiscal year, the actual contra-expense cannot exceed the actual eligible expenses.

GEP revenues earned in FY 2012-2013 are a revenue credit in the FY 2012-2013 Composite cost pool. This revenue credit will be subject to the Composite Cost Pool True-Up.

### 7.3.6 Interest Earned on the Bonneville Fund

TRM section 2.5 states that future circumstances may occur that make it reasonable and fair to make additional adjustments to the size of the base amount of financial reserves attributed to the Power function as of October 1, 2001. The TRM describes several circumstances that could occur. The base amount ($495.6 million) is the amount on which an interest credit is calculated for ratemaking purposes for crediting to the Composite cost pool.

Table 4 displays the circumstances and the related adjustments to the size of the base amount ($495.6 million). The revised amount is $496.40 million.

The amounts contained in Table 4 have not been shared with or collected from Slice customers through a prior Slice True-Up, so these amounts will be adjustments to the size of the base amount of financial reserves. The payments or funds that BPA received are reflected as negative amounts in Table 4 and will increase the size of the base amount of financial reserves. BPA's payments for settlements or judgments, and BPA's write-off of bad debt expense, are reflected as positive amounts in Table 4 and will decrease the size of the base amount of financial reserves.

To the extent that BPA receives payments or makes payments during a fiscal year of the FY 2012-2013 rate period and the payments can be categorized into one of the types of receipts or payments described in the TRM, and those receipts or payments have not been proportionally allocated to Slice customers through their Slice True-Up Adjustment Charges during the rate period, then BPA will make an adjustment to the size of the base amount of financial reserves.

The interest credit on the financial reserves amount will be subject to the Composite Cost Pool True-Up. The actual interest credit calculated on the base amount of financial reserves can change from forecast interest credit due to changes in interest credit calculation factors from forecast factors. See Revenue Requirement Study Documentation, section 5, for a description of how the interest credit calculation factors can change from final rate case studies.

#### 7.3.7 Bad Debt Expenses

Bad debt expenses could be allocated between the Composite cost pool and the Non-Slice cost pool. TRM, Table 2A. There is no forecast bad debt expense for the FY 2012-2013 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, there would first be a determination of whether the expense would 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. TRM section 2.1.

Any bad debt expense associated with a sale to any customer that purchased Federal power exclusively at the FPS-02, FPS-07, FPS-07S, FPS-10, and FPS-12 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 attributable to BPA's marketing of secondary energy after the inception of the Slice product, and are included in the Non-Slice cost pool. See TRM section 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 entirely contingent on the facts and circumstances of the particular instance of a full or partial non-payment of a power bill. BPA will not determine a particular cost treatment in the absence of specific information on the transaction to guide this determination. There have been no bad debt allocations at issue since BPA's decisions to include any bad debt expenses arising from mixed transactions in the Slice True-Up Adjustment Charge calculation. BPA will defer any determination of allocation to the Composite cost pool until an instance of bad debt expenses arises.

Any future bad debt expense related to write-offs of any outstanding California Independent System Operator (CAISO) or California Power Exchange (Cal PX) receivables for transactions prior to October 1, 2001, will be excluded for Composite Cost Pool True-Up purposes. Such bad debt expenses were specifically excluded as part of the Slice Settlement Agreement (07PB-12273), which was effective until September 30, 2011. This exclusion is proposed for continuation for the BP-12 rate period.

Any bad debt expenses related to write-offs of any outstanding receivables arising out of FPS power sales transactions (other than with CAISO or Cal PX) prior to October 1, 2001, will be included for Composite Cost Pool True-Up purposes. Such bad debt expenses were not specifically excluded as part of the Slice Settlement Agreement. Such bad debt expenses will be included for Composite Cost Pool True-Up purposes because FPS power sales transactions prior to October 1, 2001, benefited all customers, as there was no Slice product prior to that date.

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 Subscription Slice True-Up Adjustment Charge or RD Slice True-Up Adjustment Charge.

For the categories of bad debt expenses specifically excluded from the Subscription Slice True-Up Adjustment Charges since FY 2002, any related revenue recoveries of such bad debt expenses will be excluded for purposes of the Composite Cost Pool True-Up. This treatment is consistent with cost causation principles. See TRM section 2.1. Since Slice customers did not share in these bad debt expenses, Slice customers will not share in any related revenue recoveries.

#### 7.3.8 Settlement or Judgment Amounts

BPA payments or BPA 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 (which is after rates are set), there will be a determination of whether it 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, section 2.1.

#### 7.3.9 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. See TRM 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 will not be subject to the Composite Cost Pool True-Up.

Transmission reservations are set aside for non-discretionary obligations (*i.e.*, Designated BPA System Obligations). Since 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 will not be subject to the Composite Cost Pool True-Up.

Any revenue from resales 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 will be 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. Since 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 rate case will not be included in the Composite Cost Pool True-Up, such principle requires that revenues from sales of surplus transmission inventory also be excluded from the Composite Cost Pool True-Up.

### 7.3.10 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 for an explanation of the calculation of this credit.

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

### 7.3.11 Resource Support Services Revenue Credit

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

### 7.3.12 Tier 2 Rate Adjustments

Tier 2 rate adjustments are ratesetting adjustments to the Composite cost pool to reflect a share of expenses that are incurred by Power Services allocable to all power sold. See section 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 section 3.1.7.1. The Tier 2 overhead cost adder will be included in the Composite cost pool. This adjustment will be estimated for ratesetting purposes and not subject to the Composite Cost Pool True-Up.

The Tier 2 risk adder is an adjustment for any risks associated with resource costs that Power Services acquires for service to Tier 2 load. This adjustment is zero for the FY 2012-2013 rate period because no risk mitigation treatment is necessary. See section 3.1.7.4. This adjustment will not be 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 will not be subject to the Composite Cost Pool True-Up.

### 7.3.13 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.

The Composite Cost Pool True-Up Table will reflect annual Composite cost pool totals that are lower than the Composite cost pool total calculated in RAM for setting the Composite Customer rate. The differences are due to the Refund Amounts ($76.538M in FY 2012 and $76.538M in FY 2013). See section 2.2.1.3.. These differences are appropriate for Composite Cost Pool True-Up purposes to ensure that Slice customers do not receive a share of the Refund Amounts through their Slice True-Up Adjustment Charge. Slice customers will receive their Refund Amounts on their monthly bills.

### 7.4 Slice Cost Pool True-Up

The Slice Cost Pool True-Up refers to the calculation of the annual Slice True-Up Adjustment for the Slice Cost Pool, which is described in the TRM. See TRM section 2.72. The Slice cost pool is shown in GRSP II.R, Table 1. Slice expenses and credits are forecast to be zero in FY 2012-2013. 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.

### 7.5 Adjustment of Slice Percentages for Additional CHWM for Jefferson County PUD

BPA will establish an Additional CHWM for Jefferson County PUD. For the BP-12 Final Proposal, BPA used its best available forecast of Jefferson County PUD's CHWM to calculate rates. See section 1.6. Although Jefferson County PUD's CHWM may change from the amount used to establish Slice Percentages, the Slice Percentages for FY 2012-2013 will not be adjusted. Slice Percentages for FY 2012-2013 were determined using the Additional CHWM from the BP-12 Final Proposal. These Slice Percentages are contained in Exhibit K of the Slice and Block contract.

# 8. AVERAGE SYSTEM COSTS

## 8.1 Overview of Average System Cost and the Residential Exchange Program

One of the components of the REP is the participating utilities' Average System Costs (ASC), which are determined in a separate 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 2008 ASCM is an administrative rule that governs BPA's calculation of ASCs. The Federal Energy Regulatory Commission granted final approval to the 2008 ASCM on September 4, 2009.

BPA has adopted the 2012 REP Settlement. The Settlement establishes a fixed stream of REP benefits that are payable to the IOUs for the period beginning in FY 2012 and ending in FY 2028. Distribution of the REP benefits under the Settlement will continue as under the traditional REP. BPA will compare the IOUs' respective ASCs with their PF Exchange rates and, if the difference is positive, multiply the difference by the IOUs' exchange loads. Thus, IOUs' ASCs and exchange loads for FY 2012-2013 are needed to determine the REP benefits provided to individual IOU participants consistent with the Settlement. Similarly, for the two COUs participating in the REP, BPA will compare their respective ASCs with their PF Exchange rates and, if the difference is positive, multiply the difference by their exchange loads. The COU REP benefits are in addition to the fixed stream of IOU REP benefits under the Settlement.

## 8.2 Overview of ASC Determinations

An ASC is calculated by dividing a utility's allowable resource costs (Contract System Cost) by the utility's allowable load (Contract System Load). The quotient is the utility's ASC ($/MWh). Contract System Cost is the sum of the utility's allowable generation- and transmission-related costs and overheads. Contract System Load is the sum of 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-12 rates were determined in Final ASC Reports published on July 25, 2011. These Final ASC Reports reflect the utilities' ASCs for the BP-12 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.

Under the 2012 REP Settlement, participating IOUs agreed to refrain from filing for ASC revisions based upon new resources coming on line or retiring during the Exchange Period (the Exchange Period is identical to the rate period). Under the REP Settlement, the ASCs that are effective on the first day of the rate period would persist throughout the Exchange Period. Therefore, "day-one" ASCs have been developed for use in establishing rates under the REP Settlement.

Two utilities have new resources or new NLSLs that are scheduled to begin operation between the date of the Final ASC Reports (July 25, 2011) and the start of the Exchange Period. The day-one ASCs used for the BP-12 rates assume that these new resources or new NLSLs are operating prior to the start of the Exchange Period. If they fail to do so, then the actual ASCs and individual utility benefits will differ from the BP-12 values. If there is a change to any ASC used in setting rates, utility-specific 7(b)(3) surcharges for all REP participants will be recomputed using GRSP II.O. The day-one ASCs are shown in Table 2.1.3 of the Documentation.

## 8.3 BP-12 Residential and Small Farm Exchange Loads

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

Utilities intending to participate in the REP for FY 2012-2013 were required to submit with their ASC filings in June 2010 a forecast of their residential and small farm sales (reflecting their exchange loads), measured at the retail meter, for FY 2012-2017. The forecast REP exchange loads for FY 2012-2013 were increased to reflect distribution losses.

Under the 2012 REP Settlement, participating IOUs agreed to use a two-year historical average for determining the exchange load used to calculate REP benefits, referred to as Residential Load. Residential Load is determined in the BP-12 ratemaking process pursuant to the terms of the Settlement and published in GRSP II.N. For the COUs, the FY 2012-2013 exchange load forecasts are based on the exchange load information provided by the COUs in the ASC Review Processes. COU REP benefits will be paid on actual residential and small farm sales for each COU, as submitted after the conclusion of each month during the rate period.

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# Power Rates Tables

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## Table 1: Rate Period High Water Marks for FY 2012-2013

| Table of RHWMs for FY 2012 - FY 2013 | | |
|---|---|---|
| A | B | C |
| | **Preference Customer** | **RHWM aMW** |
| 1) | Albion, City of | 0.404 |
| 2) | Alder Mutual Light Company | 0.556 |
| 3) | Ashland, City of | 21.383 |
| 4) | Asotin County PUD | 0.610 |
| 5) | Bandon, City of | 7.753 |
| 6) | Benton County PUD | 204.642 |
| 7) | Benton Rural Electric Association | 67.956 |
| 8) | Big Bend Electric Cooperative, Inc. | 62.107 |
| 9) | Blachly-Lane Electric Cooperative | 17.879 |
| 10) | Blaine, City of | 8.877 |
| 11) | Bonners Ferry, City of | 5.399 |
| 12) | Burley, City of | 14.274 |
| 13) | Canby Utility | 20.612 |
| 14) | Cascade Locks, City of | 2.638 |
| 15) | Central Electric Cooperative, Inc. | 83.072 |
| 16) | Central Lincoln People's Utility District | 159.010 |
| 17) | Centralia, City of | 24.735 |
| 18) | Cheney, City of | 16.053 |
| 19) | Chewelah, City of | 2.887 |
| 20) | Clallam County PUD No. 1 | 77.162 |
| 21) | Clark Public Utilities | 323.245 |
| 22) | Clatskanie People's Utility District | 94.974 |
| 23) | Clearwater Power Company | 24.523 |
| 24) | Columbia Basin Electric Cooperative, Inc. | 12.299 |
| 25) | Columbia Power Cooperative Association | 3.283 |
| 26) | Columbia River People's Utility District | 61.254 |
| 27) | Columbia Rural Electric Cooperative, Inc. | 38.255 |
| 28) | Consolidated Irrigation District #19 | 0.231 |
| 29) | Consumers Power, Inc. | 46.355 |
| 30) | Coos-Curry Electric Cooperative, Inc. | 41.485 |
| 31) | Coulee Dam, Town of | 2.055 |
| 32) | Cowlitz County PUD | 557.392 |
| 33) | Declo, City of | 0.364 |
| 34) | DOE National Energy Technology Laboratory | 0.465 |

| Table of RHWMs for FY 2012 - FY 2013 | | |
|---|---|---|
| A | B | C |
| | **Preference Customer** | **RHWM aMW** |
| 35) | DOE Richland | 26.651 |
| 36) | Douglas Electric Cooperative, In. | 19.291 |
| 37) | Drain, City of | 2.479 |
| 38) | East End Mutual Electric Co., Ltd. | 2.727 |
| 39) | Eatonville, Town of | 3.418 |
| 40) | Ellensburg, City of | 24.340 |
| 41) | Elmhurst Mutual Power & Light Company | 32.719 |
| 42) | Emerald People's Utility District | 53.228 |
| 43) | Energy Northwest | 2.910 |
| 44) | Eugene Water and Electric Board | 254.843 |
| 45) | Fairchild Air Force Base | 7.402 |
| 46) | Fall River Rural Electric Cooperative, Inc. | 33.624 |
| 47) | Farmers Electric Company | 0.515 |
| 48) | Ferry County PUD No. 1 | 11.839 |
| 49) | Flathead Electric Cooperative, Inc. | 169.311 |
| 50) | Forest Grove, City of | 27.275 |
| 51) | Franklin County PUD No. 1 | 119.102 |
| 52) | Glacier Electric Cooperative, Inc | 21.635 |
| 53) | Grant County PUD No. 2 - Grand Coulee | 5.269 |
| 54) | Grays Harbor County PUD No. 1 | 133.174 |
| 55) | Harney Electric Cooperative, Inc. | 23.092 |
| 56) | Hermiston, City of | 13.130 |
| 57) | Heyburn, City of | 4.889 |
| 58) | Hood River Electric Cooperative | 13.294 |
| 59) | Idaho County Light & Power Coop. | 6.306 |
| 60) | Idaho Falls Power | 80.743 |
| 61) | Inland Power & Light Company | 109.349 |
| 62) | Jefferson County PUD No. 1 | 40.772 |
| 63) | Kittitas County PUD No. 1 | 9.847 |
| 64) | Klickitat County PUD | 37.206 |
| 65) | Kootenai Electric Cooperative, Inc. | 51.760 |
| 66) | Lakeview Light & Power | 33.839 |
| 67) | Lane Electric Cooperative, Inc. | 29.537 |
| 68) | Lewis County PUD No. 1 | 115.429 |
| 69) | Lincoln Electric Cooperative, Inc. | 14.789 |
| 70) | Lost River Electric Cooperative, Inc. | 9.668 |
| 71) | Lower Valley Energy | 87.321 |
| 72) | Mason County PUD No. 1 | 9.121 |

| Table of RHWMs for FY 2012 - FY 2013 | | |
|---|---|---|
| A | B | C |
| | **Preference Customer** | **RHWM aMW** |
| 73) | Mason County PUD No. 3 | 81.121 |
| 74) | McCleary, City of | 4.236 |
| 75) | McMinnville Water and Light | 105.779 |
| 76) | Midstate Electric Cooperative, Inc. | 47.443 |
| 77) | Milton Freewater, City of | 10.698 |
| 78) | Milton, City of | 7.548 |
| 79) | Minidoka, City of | 0.120 |
| 80) | Mission Valley Power | 38.518 |
| 81) | Missoula Electric Cooperative, Inc. | 27.388 |
| 82) | Modern Electric Water Company | 26.677 |
| 83) | Monmouth, City of | 8.488 |
| 84) | Nespelem Valley Electric Cooperative, Inc. | 5.969 |
| 85) | Northern Lights, Inc. | 36.464 |
| 86) | Northern Wasco County PUD | 65.731 |
| 87) | Ohop Mutual Light Company | 10.310 |
| 88) | Okanogan County Electric Coop, Inc | 6.626 |
| 89) | Okanogan County PUD No. 1 | 49.678 |
| 90) | Orcas Power and Light Cooperative | 25.103 |
| 91) | Oregon Trail Electric Consumers Cooperative, Inc. | 82.488 |
| 92) | Pacific County PUD No. 2 | 36.869 |
| 93) | Parkland Light and Water Company | 14.278 |
| 94) | Pend Oreille County PUD No. 1 | 29.444 |
| 95) | Peninsula Light Company, Inc. | 73.059 |
| 96) | Plummer, City of | 4.004 |
| 97) | Port Angeles, City of | 86.755 |
| 98) | Port of Seattle | 17.536 |
| 99) | Raft River Rural Electric Cooperative, Inc. | 38.633 |
| 100) | Ravalli County Electric Cooperative, Inc. | 18.791 |
| 101) | Richland, City of | 102.600 |
| 102) | Riverside Electric Company | 2.408 |
| 103) | Rupert, City of | 9.563 |
| 104) | Salem Electric | 39.976 |
| 105) | Salmon River Electric Cooperative | 31.857 |
| 106) | Seattle City Light | 531.727 |
| 107) | Skamania County PUD No. 1 | 16.144 |
| 108) | Snohomish County PUD No. 1 | 810.990 |
| 109) | Soda Springs, City of | 3.103 |

| Table of RHWMs for FY 2012 - FY 2013 | | |
|---|---|---|
| A | B | C |
| | **Preference Customer** | **RHWM aMW** |
| 110) | South Side Electric, Inc. | 6.866 |
| 111) | Springfield Utility Board | 102.208 |
| 112) | Steilacoom, Town of | 4.880 |
| 113) | Sumas, City of | 3.697 |
| 114) | Surprise Valley Electric Corp. | 16.677 |
| 115) | Tacoma Public Utilities | 408.393 |
| 116) | Tanner Electric Cooperative | 11.197 |
| 117) | Tillamook People's Utility District | 56.865 |
| 118) | Troy, City of | 2.068 |
| 119) | U.S. Dept of the Navy - Bremerton | 30.914 |
| 120) | U.S. Dept of the Navy - Everett | 1.550 |
| 121) | U.S. Dept. of the Navy - Bangor | 20.726 |
| 122) | Umatilla Electric Cooperative | 114.912 |
| 123) | Umpqua Indian Utility Cooperative | 3.580 |
| 124) | United Electric Cooperative, Inc. | 30.424 |
| 125) | US BIA - Wapato | 1.846 |
| 126) | Vera Water & Power | 27.562 |
| 127) | Vigilante Electric Cooperative, Inc. | 19.438 |
| 128) | Wahkiakum County PUD No. 1 | 5.080 |
| 129) | Wasco Electric Cooperative, Inc. | 13.596 |
| 130) | Weiser, City of | 6.423 |
| 131) | Wells Rural Electric Company | 97.200 |
| 132) | West Oregon Electric Cooperative, Inc. | 8.735 |
| 133) | Whatcom County PUD No. 1 | 27.233 |
| 134) | Yakama Power | 4.768 |

## Table 2: Revenues at Current Rates

| | B C D E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|
| 1 | **Revenues at Current Rates** | **2011** | | **2012** | | **2013** | |
| 2 | **Category** | **$ (000's)** | **aMW** | **$ (000's)** | **aMW** | **$ (000's)** | **aMW** |
| 3 | PF Full Service | $513,221 | 2,054 | $813,985 | 3,190 | $829,296 | 3,240 |
| 4 | PF Partial Service | $369,808 | 1,442 | $0 | - | $0 | - |
| 5 | PF Block Service | $437,716 | 1,762 | $440,008 | 1,791 | $448,171 | 1,831 |
| 6 | PF Slice | $528,134 | 2,183 | $636,495 | 1,879 | $636,495 | 1,879 |
| 7 | Irrigation Mitigation / Irrigation Rate Discount | $22,929 | 198 | ($13,172) | - | ($13,172) | - |
| 8 | Low Density Discount | $0 | - | ($27,039) | - | ($28,531) | - |
| 9 | PF customers (Subscription) sub-total | **$1,871,808** | **7,638** | **$1,850,277** | **6,860** | **$1,872,259** | **6,951** |
| 10 | DSIs sub-total | $103,078 | 340 | $103,350 | 340 | $103,076 | 340 |
| 11 | FPS sub-total | $38,985 | 168 | $1,716 | 8 | $1,778 | 8 |
| 12 | Short-term market sales sub-total | $463,168 | 2,095 | $447,327 | 1,769 | $459,653 | 1,652 |
| 13 | Long Term Contractual Obligations sub-total | $90,029 | 91 | $30,217 | 65 | $29,865 | 62 |
| 14 | Canadian Entitlement Return | $0 | 534 | $0 | 522 | $0 | 505 |
| 15 | Renewable Energy Certificates sub-total | $3,934 | - | $2,658 | 40 | $2,836 | 40 |
| 16 | Other Sales sub-total | $10,918 | - | $5,506 | - | $5,498 | - |
| 17 | **Gross Sales** | **$2,581,920** | **10,867** | **$2,441,051** | **9,605** | **$2,474,965** | **9,559** |
| 18 | **Miscellaneous Revenues** | **$25,572** | **180** | **$26,198** | **178** | **$26,335** | **178** |
| 19 | **Generation Inputs / Inter-business line** | **$105,249** | **9** | **$127,449** | **9** | **$131,078** | **9** |
| 20 | 4(h)(10)(c) | $87,013 | - | $91,062 | - | $95,847 | - |
| 21 | Colville and Spokane Settlements | $4,600 | - | $4,600 | - | $4,600 | - |
| 22 | **Treasury Credits** | **$91,613** | - | **$95,662** | - | **$100,447** | - |
| 23 | Augmentation Power Purchase total | $2,843 | 11 | $0 | - | $66,150 | 176 |
| 24 | Balancing Power Purchase sub-total | $157,229 | 480 | $46,827 | 231 | $29,559 | 140 |
| 25 | Other Power Purchase total | $47,767 | 93 | $52,974 | 105 | $66,492 | 140 |
| 26 | **Power Purchases** | **$207,839** | **583** | **$99,802** | **335** | **$162,201** | **456** |

## Table 3: Revenues at Proposed Rates

| | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Revenues at Proposed Rates** | | | | **2011** | | **2012** | | **2013** | |
| 2 | **Category** | | | | **$ (000's)** | **aMW** | **$ (000's)** | **aMW** | **$ (000's)** | **aMW** |
| 3 | | | PF customers (Subscription) sub-total | | **$1,871,808** | **7,638** | **-** | **-** | **-** | **-** |
| 4 | | | Composite Revenue | | - | - | $2,248,831 | 6,911 | $2,276,003 | 6,959 |
| 5 | | | Non-Slice Revenue | | - | - | ($322,551) | - | ($327,962) | - |
| 6 | | | Slice Revenue | | - | - | $0 | - | $0 | - |
| 7 | | | Load Shaping Revenue | | - | - | $8,604 | 21 | $24,123 | 54 |
| 8 | | | Demand Revenue | | - | - | ($16,910) | (33) | ($11,256) | (17) |
| 9 | | | Irrigation Rate Discount | | - | - | $58,932 | - | $61,269 | - |
| 10 | | | Low Density Discount | | - | - | ($19,305) | - | ($19,305) | - |
| 11 | | | Tier 2 | | - | - | ($31,768) | - | ($32,944) | - |
| 12 | | | RSS (Non-Federal) | | - | - | $309 | - | $317 | - |
| 13 | | | PF customers (CHWM) sub-total | | **-** | **-** | **$1,926,143** | **6,900** | **$1,970,246** | **6,996** |
| 14 | | | DSIs sub-total | | $103,078 | 340 | $108,618 | 341 | $108,334 | 341 |
| 15 | | | Pre-Subscription (FPS) sub-total | | $38,985 | 168 | $1,716 | 8 | $1,778 | 8 |
| 16 | | | Short-term market sales sub-total | | $463,168 | 2,095 | $447,327 | 1,769 | $459,653 | 1,652 |
| 17 | | | Long Term Contractual Obligations sub-total | | $90,029 | 91 | $30,217 | 65 | $29,865 | 62 |
| 18 | | | Canadian Entitlement Return | | $0 | 534 | $0 | 522 | $0 | 505 |
| 19 | | | Renewable Energy Certificates sub-total | | $3,934 | - | $2,658 | 40 | $2,836 | 40 |
| 20 | | | Other Sales sub-total | | $10,918 | - | $5,506 | - | $5,498 | - |
| 21 | **Gross Sales** | | | | **$2,581,920** | **10,867** | **$2,522,186** | **9,645** | **$2,578,210** | **9,605** |
| 22 | **Miscellaneous Revenues** | | | | **$25,572** | **180** | **$26,198** | **178** | **$26,335** | **178** |
| 23 | **Generation Inputs / Inter-business line** | | | | **$105,249** | **9** | **$127,449** | **9** | **$131,078** | **9** |
| 24 | | | 4(h)(10)(c) | | $87,013 | - | $91,062 | - | $95,847 | - |
| 25 | | | Colville and Spokane Settlements | | $4,600 | - | $4,600 | - | $4,600 | - |
| 26 | **Treasury Credits** | | | | **$91,613** | **-** | **$95,662** | **-** | **$100,447** | **-** |
| 27 | | | Augmentation Power Purchase sub-total | | $2,843 | 11 | $0 | - | $66,150 | 176 |
| 28 | | | Balancing Power Purchase sub-total | | $157,229 | 480 | $46,827 | 231 | $29,559 | 140 |
| 29 | | | Other Power Purchase sub-total | | $47,767 | 93 | $52,974 | 105 | $66,492 | 140 |
| 30 | **Power Purchases** | | | | **$207,839** | **583** | **$99,802** | **335** | **$162,201** | **456** |

## Table 4: Adjustments to Financial Reserves Base Amount

| Unit | Account | Stat Amt | Ref | Line Descr | Reason for adjustment |
|---|---|---|---|---|---|
| POWER | 999044 | $ (673,094.63) | AR00114197 | Receipt from DOJ | 1 |
| POWER | 999044 | $ (104,552.35) | AR00117261 | Receipt from FERC | 1 |
| POWER | 999044 | $ (53,497.33) | AR00119524 | Receipt from DOJ | 1 |
| POWER | 999044 | $ (2,789.38) | AR00122086 | Receipt from DOJ | 1 |
| POWER | 999044 | $ (5.04) | AR00129431 | Stock dividend | 2 |
| POWER | 999044 | $ 39,274.42 | OA04101016 | CAISO balance adjustment | 4 |
| POWER | 999044 | $ (6,667.74) | AR00127956 | Receipt from FERC | 1 |
| POWER | 999044 | $ (1,528.11) | AR00128358 | Receipt from DOJ | 1 |
| POWER | 999044 | (1,080.25) | AR00143938 | Receipt from DOJ | 1 |
| | | | | | |
| | | **$ (803,940.41)** | | | |

**<u>Reasons for adjustments</u>**

1) BPA's receipt of payments for settlements or judgments pertaining to power marketing transactions that occurred before FY 2002,
2) BPA's receipt of funds as collections of outstanding receivables relating to revenues that occurred before FY 2002,
3) BPA's payment for settlements or judgments pertaining to power marketing transactions that occurred before FY 2002, and
4) BPA's write-off of bad debt expense pertaining to power marketing transactions that occurred before FY 2002.

Base amount of financial reserves = $495,600,000

Adjustment to the base amount of financial reserves = $495,600,000 + $803,940

**Resulting amount of financial reserves = $496,403,940**

Adjustment amounts, if negative, are added to the base amount of financial reserves, thereby increasing the size of the base amount.
Adjustment amounts, if positve, are subtracted from the base amount of financial reserves, thereby decreasing the size of the base amount.

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# Appendix A

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# Appendix A

# 7(c)(2) Industrial Margin Study

## 1. INTRODUCTION

Section 7(c)(1)(B) of the Northwest Power Act provides that rates applicable to 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. PURPOSE

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-12 energy charges. These adjusted PF-12 energy charges and Demand Charges are applied to the DSI billing determinants to determine the IP-12 rate.

# 3. METHODOLOGY

## 3.1 Administrator's Applicable Wholesale Rates to Public Body and Cooperative Customers

The PF-12 demand and energy charges (before any 7(b)(2) or floor rate adjustments) are applied to the forecast DSI billing determinants.

## 3.2 Typical Margin

The "typical margin" includes "other overhead costs" charged by the utilities in the study. BPA power revenue requirements are accounted for in the PF rate charges, and distribution costs are included by adding in a charge for BPA DSI delivery facilities. An overall margin is derived by weighting individual utility margins according to the proportion of industrial energy load served by each utility relative to total industrial energy load included in the study.

## 3.3 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. 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.

## 4. APPLICATION OF THE METHODOLOGY

The derivation of the margin involves two 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 margin. The BPA DSI delivery facilities charge is added as a later step to replace the distribution costs that otherwise would be included in the margin.

### 4.1 Data Base

The data base was collected 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 were required to sign confidentiality agreements at the PPC offices. All utility data reported has been identified by a randomly assigned number. This is essentiality the same way margin data was displayed in the WP-02 and WP-07 industrial margin studies. The data base consists of cost information from 33 utilities that have at least one industrial consumer with a peak load of at least 3.5 MW. Attachment A displays each participating utility's total energy used by large industrial consumers, its individual industrial margin, its weighted individual margin, and the overall energy-weighted typical industrial margin for all utilities in the BP-12 margin study.

### 4.2 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. The data for each of the utilities in the study are included as Attachment B. Various costs assigned to the “other” category are added to arrive at each utility’s industrial margin.

### 4.3 Summary of Results

The final results of each step in the margin calculation for each utility are shown in Attachment A. The BP-12 weighted industrial margin is 0.68 mills/kWh.

# 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**

BONNEVILLE POWER ADMINISTRATION

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