

2012 BPA Final Rate Proposal

Power Rates Study

July 2011

BP-12-FS-BPA-01



POWER RATES STUDY

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APPENDIX A: 7(c)(2) Industrial Margin Study

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
<i>dec</i>	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
<i>inc</i>	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 **1. INTRODUCTION AND BACKGROUND**

2 **1.1 Power Rates Study Overview**

3 The Power Rates Study (Study) explains the processes and calculations used to develop the
4 power rates and billing determinants for BPA’s wholesale power products and services. The
5 Study serves three primary purposes: (1) to demonstrate that the rates have been developed in a
6 manner consistent with statutory direction, including the initial allocation of costs and the
7 subsequent reallocations directed by statute; (2) to set rates consistent with agency policy; and
8 (3) to demonstrate that the rates have been set at a level that recovers the allocated power
9 revenue requirement for the upcoming rate period. The rate design process is illustrated in
10 section 1 of the Power Rates Study Documentation (Documentation), BP-12-FS-BPA-01A, and
11 described further throughout this Study.

12
13 The development of rates in the Study uses inputs from a variety of sources. Loads and
14 resources are provided to the Study by the Power Loads and Resources Study, BP-12-FS-
15 BPA-03, and its accompanying documentation, BP-12-FS-BPA-03A. Power revenue
16 requirement information is provided by the Power Revenue Requirement Study, BP-12-FS-
17 BPA-02, and its accompanying documentation, BP-12-FS-BPA-02A. The Power Risk and
18 Market Price Study, BP-12-FS-BPA-04, and its accompanying documentation, BP-12-FS-
19 BPA-04A, provide the Study with the electricity market price forecasts and forecast quantities of
20 power expected to be sold and purchased in electric markets. These market price forecasts are
21 used in the development of the demand rates, load shaping rates, short-term balancing purchases
22 and expenses, augmentation purchases and expenses, secondary energy sales and revenue, and
23 Planned Net Revenues for Risk (PNRR), if any. The results of the Generation Inputs Study,
24 BP-12-FS-BPA-05, are provided to the Study as revenue credits. Explanation and
25 documentation for these credits arising from generation inputs and other inter-business line cost
26 allocations are included in the Generation Inputs Study.

1 The results of the power rate development process, including rates for power products and
2 services, plus general rate schedule provisions, appear in the Power Rate Schedules, BP-12-
3 A-02B. The revenues resulting from the rates developed herein are used by the Power Revenue
4 Requirement Study in the Revised Revenue Test to test the adequacy of the rates in recovering
5 expenses and supplying adequate cash to cover non-expense cash outlays. Power Revenue
6 Requirement Study, BP-12-FS-BPA-02, section 3.3.

7 8 **1.2 Statutory and Legal Overview**

9 The Northwest Power Act, 16 U.S.C. § 839, is the most prominent statute providing ratemaking
10 directives to BPA. Section 7(a)(1) states:

11 The Administrator shall establish, and periodically review and revise, rates for the
12 sale and disposition of electric energy and capacity and for the transmission of
13 non-Federal power. Such rates shall be established and, as appropriate, revised to
14 recover, in accordance with sound business principles, the costs associated with
15 the acquisition, conservation, and transmission of electric power, including the
16 amortization of the Federal investment in the Federal Columbia River Power
17 System (including irrigation costs required to be repaid out of power revenues)
18 over a reasonable period of years and the other costs and expenses incurred by the
19 Administrator pursuant to this chapter and other provisions of law. Such rates
20 shall be established in accordance with sections 9 and 10 of the Federal Columbia
21 River Transmission System Act (16 U.S.C. § 838) [16 U.S.C. §§ 838g and 838h],
22 section 5 of the Flood Control Act of 1944 [16 U.S.C. § 825s], and the provisions
23 of this chapter.

24 Section 7(a)(1) directs the Administrator to establish, and periodically review and revise, rates
25 for the sale and disposition of electric energy and capacity and for the transmission of
26 non-Federal power. The Northwest Power Act defines “periodically review and revise” as not

1 less frequently than once in every five years. The section also directs that rates recover all of the
2 Administrator's costs, including the repayment of the Federal investment in the Federal
3 Columbia River Power System. Rates are also to be in accord with two other statutes, the
4 Transmission System Act and the Flood Control Act.

5
6 Section 7 directs the allocation of costs, which is performed in a cost of service analysis (see
7 section 2.1 of this Study), and a set of rate directives providing further guidance on how
8 individual rates are to be derived (see section 2.2).

9 10 **1.2.1 Cost of Service Analysis**

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

15
16 Section 7(b)(1) states:

17 The Administrator shall establish a rate or rates of general application for electric
18 power sold to meet the general requirements of public body, cooperative, and
19 Federal agency customers within the Pacific Northwest, and loads of electric
20 utilities under section 5(c) of this title. Such rate or rates shall recover the costs of
21 that portion of the Federal base system resources needed to supply such loads
22 until such sales exceed the Federal base system resources. Thereafter, such rate
23 or rates shall recover the cost of additional electric power as needed to supply
24 such loads, first from the electric power acquired by the Administrator under
25 section 5(c) of this title and then from other resources.

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

8
9 Section 7(b)(1) instructs that Federal base system (FBS) resources are used to serve the PF rate
10 pool until FBS resources are exhausted. Thus, a corresponding amount of FBS costs is allocated
11 to the PF rate pool. After FBS resources are fully used, resources acquired pursuant to the REP
12 (called exchange resources) are used and then, if needed, new resources are used to serve
13 remaining PF rate load. By allocating resource costs in this order, the appropriate amounts of
14 exchange and new resource costs are allocated to the PF rate pool. The allocation of these costs
15 is discussed throughout section 2.1.

16
17 Section 7(d)(1) states:

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

21
22 Section 7(d)(1) instructs BPA to apply a Low Density Discount (LDD) to mitigate the costs of
23 customers with relatively fewer customers spread over relatively larger geographic areas. The
24 LDD is discussed in sections 2.1.3.3 and 4.1.1.4.

1 Section 7(f) states:

2 Rates for all other firm power sold by the Administrator for use in the Pacific
3 Northwest shall be based upon the cost of the portions of Federal base system
4 resources, purchases of power under section 5(c) of this title and additional
5 resources which, in the determination of the Administrator, are applicable to such
6 sales.

7
8 Section 7(f) sets forth what and how costs are allocated to rates for all other firm power after
9 costs are allocated to the PF rate pool and the rates for BPA's direct-service industrial customers
10 (DSIs) are determined. Section 7(f) allocates the remaining exchange and new resource costs to
11 the remaining regional remaining load (power sold at the New Resources Firm Power (NR) rate
12 and the Firm Power Products and Services (FPS) rate). The allocation of these costs is discussed
13 throughout section 2.1.

14
15 Section 7(g) states:

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

1 Section 7(g) addresses the allocation of costs that are not covered by the previously cited
2 sections of the Northwest Power Act, such as conservation and fish and wildlife costs. The
3 allocation of these costs is discussed throughout section 2.1.

4 5 **1.2.2 Rate Directives**

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

8
9 Section 7(c) in pertinent part states:

10 The rate or rates applicable to direct service industrial customers shall be
11 established for the period beginning July 1, 1985, at a level which the
12 Administrator determines to be equitable in relation to the retail rates charged by
13 the public body and cooperative customers to their industrial consumers in the
14 region.

15
16 Section 7(c) describes how BPA is to set the rate it charges DSI customers. It provides that the
17 DSI rate will be set to be equitable in relation to retail industrial rates of consumer-owned utility
18 (COU) customers. Section 7(c) provides guidance on how to establish and modify this equitable
19 relationship.

20 The [DSI rate] shall be based upon the Administrator's applicable wholesale rates
21 to such public body and cooperative customers and the typical margins included
22 by such public body and cooperative customers in their retail industrial rates but
23 shall take into account the comparative size and character of the loads served, the
24 relative costs of electric capacity, energy, transmission, and related delivery
25 facilities provided and other service provisions, and direct and indirect overhead
26 costs, all as related to the delivery of power to industrial customers, except that

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

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

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

12
13 Section 7(c)(3) directs that the DSI rate is to be adjusted to account for the value of power
14 system reserves provided through contractual rights that allow BPA to restrict portions of the
15 DSI load. This adjustment is typically made through a Value of Reserves (VOR) credit. The
16 VOR analysis is discussed in section 3.3.1.1.

17
18 In summary, the result of section 7(c) is that the DSI rate is set equal to the applicable wholesale
19 rate, plus the typical margin, minus the VOR credit, subject to the DSI floor rate test. Because
20 the DSI rate interacts with the PF rate and the NR rate, the three rates are determined
21 simultaneously through a solution called the 7(c)(2) Delta. The determination and application of
22 the 7(c)(2) Delta is discussed in section 2.2.2.3.

23
24 Section 7(b)(2) states:

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

1 customers, exclusive of amounts charged such customers under subsection (g) of
2 this section for the costs of conservation, resource and conservation credits,
3 experimental resources and uncontrollable events, may not exceed in total, as
4 determined by the Administrator, during any year after July 1, 1985, plus the
5 ensuing four years, an amount equal to the power costs for general requirements
6 of such customers if, the Administrator assumes [five certain assumptions].
7

8 Section 7(b)(2) describes a rate test designed to ensure that preference customers' firm power
9 rates are no higher than rates calculated using five certain assumptions that remove specified
10 effects of the Northwest Power Act. In settlement of many petitions to the U.S. Court of Appeals
11 for the Ninth Circuit challenging BPA's implementation of the sections 7(b)(2) and 7(b)(3), the
12 rate test has been replaced by provisions of the 2012 REP Settlement. REP-12-A-03. The
13 Settlement provides a manner by which BPA can compute the amount of rate protection for
14 preference customers in lieu of performing the rate test and provide an agreed-upon amount for
15 REP benefits to investor-owned utilities.
16

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

18 Any amounts not charged to public body, cooperative, and Federal agency
19 customers by reason of paragraph (2) of this subsection shall be recovered
20 through supplemental rate charges for all other power sold by the Administrator to
21 all customers.
22

23 Section 7(b)(3) directs that the cost of any rate protection afforded to preference customers is
24 borne by all other BPA power sales. The rate protection does not extend to all PF customers; the
25 public body, cooperative, and Federal agency customers receive the rate protection, but REP
26 participants do not. Thus, to allow the cost reallocations due to the rate protection, the PF rate is

1 bifurcated. The two resulting rates are the PF Public rate, which receives the rate protection, and
2 the PF Exchange rate, which does not receive rate protection and bears its allocated share of the
3 rate protection reallocation. The rate protection amount is collected through additional charges
4 included in rates for all non-PF Public sales. The reallocation of rate protection costs is
5 discussed in section 2.2.1 and 2.2.3.1. The 2012 REP Settlement retains the allocation of rate
6 protection costs to all other rates through mechanisms specified in the contract.

8 **1.2.3 Rate Design**

9 Section 7(e) states:

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

13
14 BPA rates must follow the ratesetting directives of section 7, but, as characterized in the
15 legislative history of the Northwest Power Act, the rate directives govern the amount of revenue
16 the Administrator collects from each class of customers, not the rate form. This section reserves
17 rate design (how the revenue is collected) to the Administrator. Rate design is discussed in
18 section 2.3.

20 **1.3 Regional Dialogue Policy Overview**

21 In the Long-Term Regional Dialogue Policy (Policy), issued in July 2007, BPA defined its
22 power supply and marketing role for the long term. Key components of the Policy include
23 20-year power sales contracts and a tiered PF rate construct that provides each preference
24 customer with a Contract High Water Mark (CHWM), which defines its right to buy power at a
25 Tier 1 rate. Any power a utility chooses to buy from BPA for its load in excess of its CHWM is
26 priced at a Tier 2 rate that is designed to recover the marginal cost of serving this additional load.

1 In October 2008, BPA offered contracts to all of its preference customers and investor-owned
2 utilities. By December 5, 2008, all preference customers and three of seven investor-owned
3 utilities (IOUs) signed the new contracts, which went into effect immediately. Power service
4 under these contracts will commence at the start of fiscal year (FY) 2012, the first year of the
5 rate period for which rates are being developed in this study. The other four investor-owned
6 utilities are expected to sign new contracts; the rates described in this document assume such
7 signings.

8
9 In November 2008, BPA issued its Tiered Rate Methodology (see section 1.4). Together, the
10 CHWM contracts and the TRM provide long-term certainty to customers regarding their access
11 to Tier 1 rate power and to BPA regarding its obligation to serve its customers' loads.

12 13 **1.3.1 Regional Dialogue Contract Product Descriptions**

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

18
19 **Load Following.** The Load Following product supplies firm power to meet the customer's Total
20 Retail Load (TRL), less any firm power supplied by the customer from any Dedicated Resources
21 including "behind the meter" non-Federal resource amounts. The costs associated with the
22 energy and capacity necessary to provide the Load Following service will be recovered through
23 Tier 1 rate charges for Load Shaping and Demand.

24
25 **Block.** The Block product provides a planned amount of firm power to meet a customer's
26 planned annual net requirement load. To buy this product, the customer must have dedicated

1 non-Federal resources, and the customer is responsible for using those resources dedicated to its
2 TRL to meet any load in excess of its planned monthly BPA Block purchase. The costs
3 associated with the energy and capacity necessary to provide this service are recovered through
4 Tier 1 rate charges for energy and demand. No customers chose to purchase the Block-only
5 product in this first election period.

6
7 **Slice/Block.** The Slice/Block product provides a combined sale of two distinct power products:
8 (1) firm power for a customer's net requirements load and an advance sale of surplus energy
9 based on the generation shape of the Federal system, and (2) firm requirements power under a
10 block product. The costs associated with the energy and capacity necessary to provide this
11 service are recovered through Tier 1 rate charges for energy and demand.

12 13 **1.4 Tiered Rate Methodology**

14 The TRM provides for a two-tiered PF Public rate design applicable to firm requirements power
15 service for preference customers that signed a CHWM contract. The TRM establishes a
16 predictable and durable means by which to calculate BPA's PF tiered rates for power deliveries
17 beginning in FY 2012. The tiered rate design differentiates between the cost of service
18 associated with Tier 1 System Resources and the cost associated with additional amounts of
19 power sold by BPA to serve any remaining portion of a customer's net requirement, also referred
20 to as Above-Rate Period High Water Mark (Above-RHWM) load. The tiering of rates is one of
21 the final steps in the development of rates and does not alter the fundamental manner in which
22 BPA allocates costs to the various rate pools under the Northwest Power Act. This Study
23 describes the steps taken to tier the Priority Firm rates.

24
25 CHWMs, determined according to the TRM, are one basis (others are described later in this
26 section) for determining how much of each customer's net requirement purchased from BPA is

1 charged at Tier 1 rates and how much may be charged at Tier 2 rates. The CHWM for each
2 customer was calculated by BPA in FY 2011 and is used to set each customer's initial eligibility
3 to purchase power at Tier 1 rates. The individual CHWMs have been added to the respective
4 CHWM contracts.

5
6 Related to the CHWM is the RHWM, which is an expression of the CHWM scaled to the
7 expected output of resources identified as comprising the Tier 1 system. Because CHWMs were
8 determined based on the expected output of Tier 1 system resources during FY 2012-2013,
9 RHWMs for this period are equal to the CHWMs, as directed by the TRM. Each customer's
10 RHWM for FY 2012-2013 defines that customer's maximum eligibility to purchase at Tier 1
11 rates for the rate period, limited for Slice and Block customers by the purchaser's Annual Net
12 Requirement, and for Load Following customers by the purchaser's Actual Net Requirement.
13 The TRM specifies how rates will be developed that ensure, to the maximum extent possible,
14 that customers purchasing at Tier 1 rates do not pay any of the costs of serving Above-RHWM
15 load.

16
17 To meet its Above-RHWM load, a customer may purchase Federal power, non-Federal power, or
18 a combination of the two. To the extent a customer purchases Federal power for its Above-
19 RHWM load, a PF Tier 2 rate(s) will be applied to this portion of its Federal power service.

20
21 The TRM was established in the TRM-12 rate case in 2008 and the supplementary TRM-12S
22 rate case in 2009. For further details, see the resulting Records of Decision (RODs), TRM-12-
23 A-01 and TRM-12S-A-01. The TRM sets forth a process to make changes to the TRM to
24 address unintended consequences that put at risk the policy goals of the TRM. Prior to the start
25 of the BP-12 rate proceeding, BPA and customers identified five unintended consequences and
26 followed the TRM process to allow those changes to be proposed in the BP-12 rate proceeding.

1 The Administrator has adopted in the Final ROD all of the proposed changes to the TRM. The
2 TRM, as revised in the BP-12 proceeding, is incorporated in the BP-12 Final Proposal as BP-12-
3 A-03. See sections 1.2.2 and 2.2 of the Final ROD, BP-12-A-02.
4

5 **1.5 Rate Options Supporting Regional Dialogue Products**

6 **1.5.1 Above-RHWM Load Service**

7 A customer may choose to have its Above-RHWM load served as net requirements load by BPA
8 at Tier 2 rates, consistent with the appropriate contractual notice and commitment requirements,
9 which are summarized in the TRM. The Tier 2 rate alternatives currently available are the Tier 2
10 Load Growth rate and the Tier 2 Short-Term rate. The Tier 2 Vintage rate is a possible Tier 2
11 rate alternative that may be offered in the future. Additional information on the Tier 2 rate
12 alternatives can be found in BPA's *Regional Dialogue Guidebook*. A description of rates for
13 Tier 2 service can be found in section 3.1 of this document and in the PF-12 rate schedule.
14

15 Alternatively, a customer may add its own non-Federal resources to serve all or part of its
16 Above-RHWM load. The notice and commitment periods for non-Federal resources or
17 purchases are identical to those for purchases from BPA at the Tier 2 Short-Term rate.
18

19 **1.5.2 Resource Support Services**

20 BPA has developed a suite of Resource Support Services and related services for customers'
21 non-Federal resources and for pricing service from BPA at Tier 2 rates. These services include
22 Diurnal Flattening Service (DFS), Forced Outage Reserve Service (FORS), Secondary Crediting
23 Service (SCS), Resource Remarketing Service (RRS), and Transmission Curtailment
24 Management Service (TCMS). Depending on the type of resource and its output, RSS may be
25 required to be purchased from either BPA or non-Federal sources for purposes of matching the
26 resource to a planned shape and amount of load. These services enable BPA to cover the costs

1 of following the variation between planned and actual customer resource amounts and to account
2 for the impact that resource shapes and fluctuations have on BPA's cost to meet its customers'
3 net requirement load. Additional information on the RSS suite of products can be found in
4 PRS section 3.1.1.3, BPA's *Regional Dialogue Guidebook*, and the General Rate Schedule
5 Provisions (GRSPs).

6 7 **1.6 Rate Period High Water Marks**

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

14
15 BPA completed the CHW M Process in May 2011, and those CHW Ms were used to calculate
16 BP-12 rates. The one exception is Jefferson County Public Utility District (PUD). Jefferson
17 County PUD is a new public customer, and its CHW M was not finalized in time to be used in the
18 calculation of the BP-12 rates. As a result, BPA used its best available forecast of Jefferson
19 County PUD's CHW M to calculate rates for the BP-12 Final Proposal. If Jefferson County
20 PUD's final CHW M is ultimately different from the one used to calculate the BP-12 rates, BPA
21 will adjust Jefferson County PUD's Tier 1 Cost Allocator (TOCA) and Contract Demand
22 Quantity (CDQ).

23 24 **1.6.1 RHW M Outputs**

25 The RHW Ms and related outputs of the RHW M Process, including RHW M Augmentation,
26 RHW M Tier 1 System Capability, and forecast Net Requirements, are used to calculate billing

1 determinants. Billing determinants impacted by the RHWMs include (1) a forecast of power
2 sold at Load Shaping Rates, (2) the TOCAs, and (3) Unused RHWM. For the FY 2012-2013
3 rate period, the Above-RHWM load is not an output of the RHWM Process, as this amount was
4 established when the Transition Period High Water Marks (THWM) were developed (see TRM
5 section 4.3). For a description of how values calculated in the RHWM Process are used in the
6 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).

1 The aggregated load and resource data is used to calculate energy allocation factors (EAFs) that
2 the COSA modeling will use to apportion costs among rate pools. The EAFs are calculated
3 based on the priorities of service from resource pools to rate pools specified in section 7 of the
4 Northwest Power Act, and based on the principle of cost causation when section 7 does not
5 provide guidance. Section 7(b)(1) directs BPA to allocate the cost of the FBS resources to the
6 PF load pool first. When the FBS resources are not sufficient to serve all PFp and PFx loads,
7 section 7(b)(1) directs BPA to serve the remaining load, first with resources obtained by BPA
8 under section 5(c) of the Northwest Power Act—that is, the exchange resources—and then with
9 new resources, as needed. In this proposal, all of the FBS and a large portion of exchange
10 resources are needed to serve PF loads, and no new resources are needed. After all of the FBS
11 resource costs and the portion of the exchange resource costs are allocated to the PF rate pool,
12 section 7(f) of the Act directs BPA to allocate the cost of the remaining exchange resources and
13 the cost of any other resources, new resources, to all remaining load.

14
15 The COSA modeling uses revenue requirement cost data from the Power Revenue Requirement
16 Study. See Documentation Table 2.3.1. The disaggregated cost data is aggregated into BPA’s
17 ratemaking cost pools specified by section 7 of the Northwest Power Act. See Documentation
18 Table 2.3.2. Sections 7(b) and 7(f) describe how costs associated with resource pools (FBS
19 costs, exchange resource costs, and new resource costs) are to be allocated to load/rate pools.
20 Section 7(g) describes how the costs associated with the other cost pools (conservation costs,
21 BPA program costs, power-related transmission costs) are to be allocated to load/rate pools.

22
23 Functionalization of costs between the generation and transmission functions is performed in the
24 Power Revenue Requirement Study and the Transmission Revenue Requirement Study, and only
25 the costs functionalized to the generation function are included in the power revenue requirement
26 found in the COSA modeling (one exception to this is exchange resource costs; see

1 section 2.1.3.2). As stated above, the exchange resource costs are calculated internal to the
2 RAM2012. These exchange resource costs include transmission function costs. The exchange
3 resource costs are functionalized in the COSA modeling so that only the generation portion of
4 the exchange resource costs is subject to the power cost rate steps, and the transmission cost
5 portion is then added back in after the Rate Directives Step is completed. See Documentation
6 Table 2.3.4.2. In this way, the statutorily mandated power cost relationships between the various
7 rate pools are maintained without being affected by the PFX transmission function costs.

8
9 In addition to exchange resource costs, the COSA modeling uses other costs that are internally
10 generated by the RAM2012. These include some power purchase costs, revenue shortfall costs
11 associated with some rate credits, and revenues from secondary power sales. These items will be
12 covered in greater detail below.

13
14 The COSA modeling receives input data associated with various revenue credits. Some of these
15 revenue credits are associated with the operation of FBS resources and have the effect of
16 reducing the FBS resource costs to be recovered by power rates. There are also revenue credits
17 that have the effect of reducing the new resource and conservation costs. Some revenue credits
18 that are not associated with any particular cost pool are allocated to all rate pools on a pro rata
19 load basis. See Documentation Table 2.3.6.

20
21 The COSA modeling concludes by using the calculated EAFs to allocate the costs and credits to
22 the rate pools. One further adjustment to the allocated costs is necessary because the costs
23 allocated to the FPS rate pool will not be equal to the expected revenues from FPS contract sales.
24 Therefore, an FPS surplus/deficiency adjustment to the COSA allocated costs is performed
25 before the calculation of initial power rates. See Documentation Table 2.3.9. These initial

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

4 **2.1.2 Loads and Resources**

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

12
13 The Power Loads and Resources Study makes the distinction between PFp load to be served at a
14 Tier 1 price and PFp load that is subject to Tier 2 pricing. The analogous distinction also holds
15 for resources: the Power Loads and Resources Study identifies Tier 1 system resources and
16 resources whose costs will be assigned to Tier 2 cost pools. Notwithstanding this distinction in
17 the input data, the COSA allocations are performed with the tiered loads aggregated as a single
18 PFp load and the newly-purchased resources combined into one FBS resource pool. The one
19 exception to this combining of tiered inputs in the COSA calculations is that the consumer-
20 owned utility (COU) Base PFx rate used to establish whether a COU is eligible to participate in
21 the REP does not include any Tier 2 resource costs or any Tier 2 loads in its calculation. See
22 Documentation Table 2.4.8. Table 2.2.1 of the Documentation shows the ratemaking energy
23 loads and resources by pools.

24
25 The REP, created by section 5(c) of the Northwest Power Act, was designed to provide
26 residential and small farm customers of Pacific Northwest utilities a form of access to low-cost

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

13 **2.1.2.1 Load and Resource Adjustments**

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

24 Similarly, there is an amount of the FBS used to serve a group of power contracts that enhances
25 the amount of FBS available to serve the ratemaking rate pools. These contracts take the form of
26 either a capacity-energy exchange or a seasonal exchange. Each of these types of exchanges is a

1 “sale” of power that is paid for by returning more power than is delivered. In ratemaking, the
2 deliveries and the equivalent returns are removed from consideration, and the energy payment is
3 included in the FBS, increasing the size of the FBS with power at no added cost.

4
5 Finally, two obligations (the Southern Idaho exchange and the Sierra Pacific exchange) are
6 transfers of power between BPA and another utility to serve BPA load in areas remote from
7 BPA’s transmission system. The BPA load that is ultimately served is included in PF loads, and
8 retaining both the PF load and the transfer load would double-count BPA’s obligation.

9 Therefore, both the delivery of power included in loads and the receipt of an equal amount of
10 power included in resources associated with these transfers, called locational exchanges, are
11 removed. The ratemaking load-resource balance after adjustments is shown in Documentation
12 Table 2.2.2.

14 **2.1.2.2 Load Pools**

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

24
25 The Northwest Power Act states that after July 1, 1985, BPA is not required to allocate any
26 resource costs to the IP rate pool; rather, the IP rate is a formulaic rate established pursuant to

1 section 7(c). However, if DSI loads were excluded from cost allocations, loads and resources
2 would be out of balance, leaving an amount of resource costs not allocated to any loads.
3 Therefore, BPA allocates resource costs to IP loads in common with resource cost allocations to
4 all other remaining (*i.e.*, non-PF) firm power sold. Thus, beginning in 1985 with the
5 implementation of the directives of section 7(c)(1)(b) of the Northwest Power Act, BPA has had,
6 for all practical purposes, only two rate pools, the 7(b) rate pool and all other loads. The
7 resource cost allocations to the IP rate pool are adjusted later in the Rate Directives Step to
8 conform the IP rate to its formulaic basis.

9 10 **2.1.2.3 Resource Pools**

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

13
14 Defined in section 3(10) of the Northwest Power Act, the FBS resource pool consists of the costs
15 of the following resources: (1) the Federal Columbia River Power System (FCRPS) hydroelectric
16 projects; (2) resources acquired by the Administrator under long-term contracts in force on the
17 effective date of the Northwest Power Act; and (3) replacements for reductions in the capability
18 of the above resources. Market purchases of system augmentation, balancing purchases, and
19 purchases designated for Tier 2 rate purposes have been included in the FBS as replacements for
20 reductions in the capability of FBS resources. Costs expected to be incurred during the rate
21 period for FBS replacement resources are included in the FBS resource cost pool.

22
23 Exchange resources are set equal to the amount of qualifying exchange load, which implements
24 the direction in section 5(c)(1) that BPA is to purchase resources from eligible REP participants
25 and to sell an equivalent amount of electric power to the participant.

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

3 4 **2.1.2.4 Order of Resource Service to Load Pools**

5 As noted in section 2.1.1, section 7(b)(1) of the Northwest Power Act specifies how resource
6 costs must be allocated to the Priority Firm Power customer class. That is, FBS resources are
7 used to serve the PF rate pool until FBS resources are exhausted, whereupon exchange resources
8 and then new resources are used to serve remaining PF rate load. Section 7(f) of the Northwest
9 Power Act sets forth what and how costs are allocated to “all other firm power” after costs are
10 allocated to the PF rate pool: the remaining exchange and new resources costs are allocated to
11 remaining load. That remaining load is Industrial Firm Power, New Resources Firm Power, and
12 Firm Power Products and Services contracts.

13
14 For the BP-12 rates, the PF load (which at this point consists both of PFp and PFx loads) is
15 greater than the capability of the FBS resources. Therefore, all FBS costs and benefits are
16 allocated to the PF rate pool. Because the remaining PF load is less than the total exchange
17 resource under section 5(c), a pro rata share of exchange resource costs is allocated to the PF rate
18 pool in the amount necessary for the exchange resource to serve the PF load not served by FBS
19 resources. The remaining exchange resources and all new resources and their attendant costs are
20 allocated to all other firm load.

21 22 **2.1.2.5 Energy Allocation Factors**

23 Energy allocation factors are calculated for each resource pool–rate pool combination by
24 dividing the amount of annual energy load in each rate pool served from each resource pool. The
25 annual EAFs for each resource cost pool as well as for the various rate directive steps are shown
26 in Documentation Table 2.2.3. The Total Usage and Conservation allocation factors assume a

1 pro rata allocation of costs to all firm loads. For example, the Total Usage EAF for costs
2 allocated to the PF load pool is equal to the ratio of PF load to total firm load. The Total Usage
3 and Conservation EAFs are used to allocate section 7(g) costs and rate directive allocation
4 adjustments to all firm energy loads.

6 **2.1.3 Ratemaking Costs**

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

16 **2.1.3.1 Revenue Requirement**

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

25 The Power Revenue Requirement Study is based on power revenue and cost estimates for a
26 two-year rate period, FY 2012-2013. A preliminary generation revenue requirement from the

1 Power Revenue Requirement Study is supplemented in the COSA for costs that are determined
2 in other steps of the ratemaking process: projected balancing purchase power costs; system
3 augmentation costs; Planned Net Revenues for Risk (PNRR), if any; and the functionalized
4 exchange resource costs. The annual revenue requirements used for rate calculations are shown
5 in Documentation Table 2.3.2. Disaggregated costs are listed in a form consistent with the
6 income statement from the Power Revenue Requirement Study and are shown in Documentation
7 Table 2.3.1. RAM2012 uses key code mapping to allocate all costs into both the COSA cost
8 pools and the TRM cost pools. Because of the different purposes of the COSA and the TRM, the
9 COSA cost pools are not related to the TRM cost pools; however, all costs appear in both sets of
10 cost pools.

11
12 Three categories of purchased power are included in the COSA: (1) purchased power, (2) system
13 augmentation, and (3) balancing power purchases.

14
15 **Purchased Power.** The purchased power subset of purchased power costs includes the costs of
16 acquisition of power through renewable energy, wind, geothermal, and competitive acquisition
17 programs. Costs of purchased power are included in the new resources pool.

18
19 **System Augmentation.** For ratesetting purposes, it is assumed that BPA acquires resources
20 beyond the inventory represented by the system generating resources and balancing power
21 purchases. These system augmentation acquisition amounts are determined in the Power Loads
22 and Resources Study and are used to meet annual customer firm power loads in excess of annual
23 firm system resources. The forecast cost of system augmentation purchases is calculated using
24 prices under 1937 water conditions as determined in the Power Risk and Market Price Study.
25 The expense estimate for system augmentation purchases is based on the application of market
26 prices for the 50 games of the Power Risk and Market Price Study associated with 1937 water

1 conditions. System augmentation purchases are treated as FBS replacements, and as such, the
2 costs are included in and allocated as FBS costs. See Documentation Tables 2.3.1 and 2.3.2.

3
4 **Balancing Power Purchases.** The costs of power purchases and storage required to meet firm
5 deficits on a monthly/diurnal basis are included in the category of balancing power purchases.
6 Projected balancing power purchases are generally needed to serve firm loads in months other
7 than the spring fish migration period under some water conditions. The costs of balancing power
8 purchases under 3,500 games of different risk conditions are calculated by the Risk Analysis
9 Model (RiskMod). In the Power Risk and Market Price Study, average balancing purchase
10 quantities are computed and valued in RiskMod against median total balancing purchase costs
11 based upon a Monte Carlo simulation of 3,500 games. The average balancing purchase
12 quantities and median expense dollars are combined to derive an expected balancing purchase
13 price for balancing purchases from RiskMod. These prices and quantities are then passed to
14 RAM2012 to compute balancing purchase costs. Balancing power purchases are treated as FBS
15 replacements, and as such, the costs are included in and allocated as FBS costs. See
16 Documentation Tables 2.3.1 and 2.3.2.

17 18 **2.1.3.2 Functionalization of Exchange Resource Costs**

19 In the COSA, exchange resource costs are based on participating utilities' ASCs and their
20 exchange power sales to BPA. ASCs include the cost of power and transmission services
21 associated with serving a participating utility's total retail load. By definition, exchange resource
22 sales to BPA equal the exchange sales by BPA. The rate directives adjustments that occur
23 subsequent to the COSA use the results of the COSA allocations of the generation revenue
24 requirement. Therefore, because the exchange resource costs in the COSA include transmission
25 costs, the PF Exchange rate includes a transmission cost adder, and the exchange resource costs
26 are functionalized between power and transmission. The exchange resource costs functionalized

1 to power continue through the ratemaking process. The exchange resource costs functionalized
2 to transmission are removed from the generation revenue requirement for the Rate Directives
3 Step and are added back to determine the PF Exchange rate after the Rate Directives Step is
4 completed. In this way, the exchange resource costs functionalized to power are treated the same
5 as other power function costs through the rate development process. The transmission function
6 costs are collected directly from PFx loads through a transmission adder included in the PFx rate.
7 Because the amount of exchange resource costs functionalized to transmission is equal to the
8 increased revenue due to the PF Exchange rate adder, there is no net cost of these transmission
9 costs to other rates. The functionalization of exchange resource costs is shown in
10 Documentation Table 2.3.4.2.

11 12 **2.1.3.3 Low Density Discount**

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

16
17 The cost of providing the discount is computed in RAM2012 using offset quantities and the
18 internally computed TRM rates. Offset quantities are the sum of the applicable LDD
19 percentages applied to the customer-specific billing determinants. These offsets are computed in
20 the TRM Billing Determinants Model, which is a separate module of RAM2012.

21
22 The estimated cost of the LDD is shown in Documentation Table 2.3.3. The entire cost of the
23 discount is allocated to the PF load pool prior to linking the IP rate to the PF rate.
24

1 **2.1.3.4 Irrigation Rate Discount**

2 A rate discount is available to qualifying irrigation loads pursuant to CHWM contracts and the
3 TRM. The discount is a rate, expressed in mills per kilowatthour, that when applied to qualified
4 irrigation load produces a dollar credit on eligible customer power bills. The Irrigation Rate
5 Discount rate is calculated in RAM2012, as described in section 3.1.11.1. The cost of the
6 discount is computed in RAM2012 using contract irrigation loads and the internally calculated
7 rate. The entire cost of the IRD is allocated to the PF load pool prior to linking the IP rate to the
8 PF rate.

9
10 **2.1.3.5 Cost Pools**

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

15
16 **2.1.3.5.1 Section 7(b)(1) costs**

17 Section 7(b)(1) costs are associated with the resources necessary to serve PF load, including the
18 PFp load and the PFx load. For the BP-12 rates, these resources are all of the FBS resources and
19 a large portion of the exchange resources. Therefore, all FBS resource costs and most of the
20 exchange resource costs are section 7(b)(1) costs allocated to serve section 7(b)(1) loads; that is,
21 PF loads.

22
23 **2.1.3.5.2 Section 7(f) Costs**

24 Section 7(f) costs are associated with the resources necessary to serve non-PF load, including IP,
25 NR, and FPS loads. For the BP-12 rates, these resources are a small portion of the exchange
26 resources and all of the new resources. Therefore, a small portion of exchange resource costs

1 and all new resource costs are section 7(f) costs allocated to serve all remaining loads; that is, IP,
2 NR, and FPS loads.

4 **2.1.3.5.3 Section 7(g) Costs**

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

13
14 **BPA Program Costs.** Some of BPA’s program costs are not identified directly with any
15 specific resource pool. An example is the cost of defending legal challenges to BPA’s
16 ratemaking decisions. Development of these power program costs occurs in the Integrated
17 Program Review, as described in the Power Revenue Requirement Study, section 2.1. The
18 power portion appears in the COSA as BPA program costs. BPA program costs are allocated to
19 all rate pools based on the Total Usage EAFs. See Documentation Table 2.3.4.3.

20
21 **BPA Power Transmission Costs.** Power transmission expenses include the costs of serving
22 transfer service customers with Federal power wheeled under GTAs and other non-Federal
23 transmission service agreements over a third-party transmission system. It also includes the
24 costs Power Services incurs to procure transmission and ancillary services to transmit surplus
25 Federal power to purchasers that do not hold transmission contracts, primarily outside the Pacific

1 Northwest. Transmission costs are allocated to all rate pools based on the Total Usage EAFs.
2 See Documentation Table 2.3.4.3.

3 4 **2.1.3.6 Planned Net Revenues for Risk**

5 PNRR is an amount of net revenues required from power rates to ensure that cash flows from
6 proposed rates meet BPA's probability standard for repaying Power Services' portion of
7 Treasury payments on time and in full. Under the ratemaking methodology, the amount of
8 PNRR is the result of an iterative process between the RAM2012, RiskMod, Non-Operating Risk
9 Model (NORM), and ToolKit models. See Power Risk and Market Price Study section 3.3. The
10 iteration is initiated with a seed value for PNRR in Documentation Tables 2.3.1 and 2.3.2. The
11 resultant rates are used in RiskMod to produce net revenue probability distributions. These net
12 revenue distributions are then used in the ToolKit to produce a new PNRR value. See
13 Documentation Table 2.3.1. Because the PNRR is zero for the BP-12 rates, no iterative process
14 is required to determine rate levels.

15 16 **2.1.4 Revenue Credits**

17 **2.1.4.1 Downstream Benefits and Pumping Power Revenues**

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

21 22 **2.1.4.2 Section 4(h)(10)(C) Credits**

23 Section 4(h)(10)(C) credits are described in section 4.4.1. The forecast credit is calculated as
24 described in the Power Risk and Market Price Study, section 2.6.1, and supplied to RAM2012.
25 Section 4(h)(10)(C) credits are associated with FBS resources, and these credits are allocated to
26 loads that have been allocated the costs of the FBS. See Documentation Table 2.3.6.

1 **2.1.4.3 FBS Contract Obligations Revenue**

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

6
7 **2.1.4.4 Colville Credit**

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

11
12 **2.1.4.5 Energy Efficiency Revenues**

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

18
19 **2.1.4.6 Miscellaneous Revenues**

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

22
23 **2.1.4.7 Renewable Energy Certificates**

24 Revenues result from BPA's sales of Renewable Energy Certificates (RECs). The revenue is
25 based on BPA's established price for RECs of \$7.50 for FY 2012 and \$8.00 for FY 2013 and
26 renewable project output included in the FBS and new resources resource pools. The revenues

1 from Klondike III RECs are allocated to loads that have been allocated the costs of the FBS, and
2 the revenues from new resources renewable resource RECs are allocated to loads that have been
3 allocated the costs of the new resources. See Documentation Table 2.3.6.
4

5 **2.1.4.8 General Revenue Credits**

6 In the course of marketing power, Power Services generates transmission-related revenues and
7 credits. The revenues and credits are predominantly revenues associated with providing reserves
8 and energy for ancillary services, control area services, and other reliability needs. The
9 Generation Inputs Study explains and documents these credits. Revenues associated with
10 Generation Inputs, Network Wind Shaping, and RSS for non-Federal resources are allocated to
11 all loads through the General Cost EAFs. See Documentation Tables 2.3.7.5 and 2.3.7.6.
12

13 **2.1.4.9 Secondary Revenue Credits**

14 The Secondary Revenue Credit adjustment recognizes that BPA collects revenues from certain
15 power sales to which costs are not allocated. BPA credits these revenues to classes of service
16 served with firm Federal power.
17

18 The ratemaking process described above ensures that the forecast of firm resources available to
19 serve load is equal to BPA's firm load obligations under critical water conditions. However, the
20 ratesetting process also recognizes that better than critical water conditions will most likely
21 occur. Generation from water in excess of critical water conditions is called secondary energy.
22 The projected secondary energy revenue credits are included so that power rates are set at a level
23 such that revenues from all sources do not recover more than the total Power Services revenue
24 requirement.
25
26

1 The sales of energy in excess of firm obligations on a monthly/diurnal basis under 3,500 games
2 of different risk conditions are calculated by RiskMod. Power Risk and Market Price Study,
3 section 2.2.3; see also Documentation Table 2.3.8. Consistent with the Power Risk and Market
4 Price Study, average secondary sales quantities are computed and valued against median total
5 secondary revenues based upon a Monte Carlo simulation of 3,500 games. The average
6 secondary sales quantities and median revenue dollars are combined to derive an expected sales
7 price for secondary energy from RiskMod. These prices and quantities are then passed to
8 RAM2012 to compute secondary energy revenues.

9
10 The secondary revenues projected in RiskMod are for market sales expected to be made by BPA
11 and do not include the portion of secondary energy that is expected to be sold to Slice customers.
12 The ratemaking process does not consider product choice by preference customers until the Rate
13 Design Step; therefore, the sales and revenue from RiskMod are “grossed up” to reflect the
14 market value for all secondary energy expected to be produced by Federal generation. See
15 Documentation Table 2.3.8. Section 7(g) of the Northwest Power Act directs that all benefits
16 from the sale of excess electric power not otherwise allocated under section 7 be equitably
17 allocated to power rates in accordance with generally accepted ratemaking principles. Secondary
18 energy revenues are allocated to rate pools based on the FBS and new resources energy
19 allocation factors to credit the revenues against the costs of the resources producing the
20 secondary energy. See Documentation Table 2.3.8.

21 22 **2.1.5 Surplus Revenue Deficiency/Surplus Reallocation**

23 BPA sells surplus firm power under the FPS rate schedule. The COSA includes these sales in
24 the FPS rate pool and allocates costs to these sales. Sales of such firm power are not necessarily
25 made at rates that recover the exact costs allocated in the COSA to these sales. Therefore, either
26 a revenue surplus or a revenue deficiency will result when a comparison is made between the

1 costs allocated to the sales of this firm power and the revenues received from the sales of such
2 power. The expected revenue forecast from the sale of firm power, the allocated costs, and the
3 resulting revenue deficiency are shown in Documentation Table 2.3.9. This revenue deficiency
4 is allocated to all other firm power (PF, IP, and NR) rates. See Documentation Table 2.3.9.

5
6 This is the final step of the COSA. At this point, all of BPA's costs have been allocated to the
7 PF, IP, NR and FPS rate pools, as have all revenues derived from sources other than the PF, IP,
8 NR and FPS rate pools. After completion of the COSA, certain statutory reallocations of these
9 COSA-allocated costs are performed in the Rate Directives Step.

10 11 **2.2 Rate Directives Step**

12 The Rate Directives Step reallocates costs among load pools to ensure that the relationships
13 between the rates for the different classes of customers comport with the rate directives in the
14 Northwest Power Act.

15 16 **2.2.1 Description of Rate Directives Step Modeling**

17 The Rate Directives Step modeling takes as input the costs allocated to the four rate pools (PF,
18 IP, NR, and FPS) from the COSA modeling. At this point in the modeling, the allocation of
19 costs to the FPS rate pool is equal to the expected revenues from FPS sales and will not be
20 altered throughout the remaining ratemaking steps. All costs and credits have been allocated to
21 rate pools in the COSA. The Rate Directives Step will adjust the initial allocations among the
22 PF, IP, and NR rate pools with reallocations of costs that conform with section 7 of the
23 Northwest Power Act.

1 **2.2.1.1 First IP-PF Rate Link**

2 The IP rate for sales of power to BPA’s DSI customers is a formula rate tied to the unbifurcated
3 PF rate (*i.e.*, the PF rate at this point in the modeling includes costs that will be allocated
4 between the PFp rate and the PFx rate later in the process). Also at this point in the modeling,
5 the costs allocated to the IP and NR rate pools are equal on a per-megawatthour basis.
6 Therefore, an adjustment is needed to set the IP rate to its proper relationship with the PF rate.
7 That adjustment, the IP-PF Link 7(c)(2) rate adjustment, will reduce the allocated costs to the IP
8 rate pool and increase the costs allocated to the PF and NR rate pools. The IP-PF Link
9 adjustment sets the IP rate to be equal to the monthly/diurnal PFp energy rates applied to DSI
10 billing determinants, plus the net industrial margin. The model first calculates the net industrial
11 margin by subtracting the Value of Reserves provided by sales to the DSIs from the typical
12 industrial margin calculated in the 7(c)(2) Margin Study, Appendix A of this Study. See
13 Documentation Table 2.4.1. Monthly and diurnally differentiated PF melded rates are calculated
14 as described in section 3.1.12. See Documentation Tables 2.4.2 and 2.4.3. Because the IP-PF
15 Link calculation consists of maintaining a set relationship between the levels of the IP and PF
16 rates for each year while simultaneously allocating costs between the two rates, and to avoid
17 multiple iterations, RAM2012 has an algebraic formula to approximate a solution and then uses
18 an intrinsic Excel function, “Goal Seek,” to converge to a solution for each year of the rate test
19 period. See Documentation Table 2.4.4.

20
21 After the IP-PF Link reallocation, RAM2012 conducts an IP floor rate test to determine if the
22 currently calculated IP rate is below the IP rate that was in effect for the contract year ending on
23 June 30, 1985, as required by section 7(c)(2) of the Northwest Power Act. The currently
24 modeled (BP-12) IP rate at this point in the modeling is not below the IP floor rate, and no floor
25 rate adjustment is needed.

1 **2.2.1.2 Determine Active Exchanging Utilities**

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

9
10 **2.2.1.3 Calculate 7(b)(2) Rate Protection and 7(b)(3) Reallocations**

11 Once these steps are complete, the next step is to calculate the level of rate protection due to
12 preference customers pursuant to section 7(b)(2) of the Northwest Power Act. The BP-12 rates
13 are calculated pursuant to a settlement of the outstanding litigation associated with the REP and
14 the section 7(b)(2) rate test. This settlement effectively implements the section 7(b)(2) rate test
15 through other calculations that provide preference customers with an amount of rate protection
16 based on the express settlement amount of IOU REP benefits, any COU REP benefits for
17 qualified REP participants, and the IP and NR rates as specified in the REP Settlement.

18
19 The rate modeling begins with total IOU REP benefits, as specified in the 2012 REP Settlement
20 and known as Scheduled Amounts. Added to this total IOU REP benefit amount are the Refund
21 Amounts, also specified in the 2012 REP Settlement. The Refund Amounts are credited back to
22 preference customers in the form of a credit on their power bills. Together these amounts are
23 referred to as REP Recovery Amounts. See Documentation Table 2.4.9.

24
25 The REP Settlement rates modeling first calculates the Unconstrained Benefits, which are the
26 REP benefits that would be in place if there was no PFp rate protection. In such circumstance,
27 the REP benefits for each exchanging utility would be its ASC minus its appropriate Base PFx

1 rate multiplied by its qualified exchange load. The Unconstrained Benefits are shown in
2 Documentation Table 2.4.10. These Unconstrained Benefits are then used to calculate COU
3 REP benefits, as specified in individual settlements with each eligible COU. COU REP benefits
4 are calculated determining a ratio of (i) the IOU Scheduled Amounts plus COU Settlement
5 Amount to (ii) the total IOU Unconstrained Benefits for IOUs. This ratio is then multiplied by
6 COU Unconstrained Benefits to derive COU REP benefits.

7
8 The total rate protection provided to preference customers is composed of two parts. With the
9 Unconstrained Benefits and the total IOU and COU REP benefits determined, the first part of
10 rate protection due to preference customers is calculated as the Unconstrained Benefits minus the
11 sum of REP benefits. The REP Settlement modeling then allocates this amount to individual
12 REP participants. Next, the cost of providing Refund Amounts is allocated to the IOU REP
13 participants. The sum of these two specific allocations to each REP participant is divided by the
14 exchange load for each participant, calculating a utility-specific 7(b)(3) Surcharge that is added
15 to the appropriate Base PFX rates to produce a utility-specific PFX rate. See Documentation
16 Table 2.4.12. After the utility-specific PFX rates are calculated, the utility-specific REP benefits
17 are calculated and summed. See Documentation Table 2.4.12.

18
19 A second part of rate protection is calculated and allocated to the IP and NR rate pools, the REP
20 Surcharge. The REP Surcharge is determined by multiplying the REP benefit costs determined
21 above (REP Recovery Amounts plus COU REP benefits) by a scalar specified in the 2012 REP
22 Settlement. The scalar is based on the WP-10 7(b)(3) rate surcharge to the IP and NR rates, and
23 changes this historical 7(b)(3) rate surcharge as REP Recovery Amounts change. This REP
24 Surcharge, when multiplied by the forecast sales under the IP and NR rate schedules, produces
25 an amount of rate protection dollars. See Documentation Table 2.4.14. This amount is allocated
26 to the IP and NR rate pools.

1 The RAM2012 REP Settlement modeling explicitly adjusts dollars between the PFp, PFx, IP,
2 and NR rate pools. The REP Settlement rate protection allocations have the effect of increasing
3 the IP, NR, and PFx rates while decreasing the PFp rate. See Documentation Table 2.4.15.
4

5 **2.2.1.4 Second IP-PF Rate Link**

6 After the IP and NR adjustment, the now-lower PFp rate and the now-higher IP rate must be
7 adjusted to maintain the proper 7(c)(2) rate directive cost relationship. For this second IP-PF
8 Link calculation, monthly/diurnal PFp energy rates are determined, and the IP rate is set equal to
9 the flat PFp rate plus the net Industrial Margin plus the REP Surcharge. See Documentation
10 Tables 2.4.16, 2.4.17, and 2.4.18.
11

12 **2.2.2 IP Rate**

13 The IP rate is based on sections 7(c)(1), 7(c)(2), and 7(c)(3) of the Northwest Power Act.
14 Section 7(c)(1)(B) provides that, after July 1, 1985, the rates to DSI customers will be set “at a
15 level which the Administrator determines to be equitable in relation to the retail rates charged by
16 the public body and cooperative customers to their industrial consumers in the region.”
17 “Equitable in relation” is defined pursuant to section 7(c)(2) as basing the DSI rate on BPA’s
18 “applicable wholesale rates” to its COU customers plus the “typical margins” included by those
19 customers in their retail industrial rates. Section 7(c)(3) provides that the DSI rate is to be
20 adjusted to account for the value of power system reserves provided through contractual rights
21 that allow BPA to restrict portions of the DSI load. This adjustment is made through a Value of
22 Reserves credit. Thus, the rate for the DSIs, the IP rate, is set equal to the applicable wholesale
23 rate, plus the typical margin, plus the VOR credit, subject to the DSI floor rate test and the
24 outcome of the determination of PFp rate protection.
25

1 **2.2.2.1 Applicable Wholesale Rate**

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

7
8 **2.2.2.2 Typical Margin, Value of Reserves, and Net Industrial Margin**

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

15
16 **2.2.2.3 IP-PF Link 7(c)(2) Adjustment**

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

1 **2.2.2.4 IP Floor Rate Verification**

2 Section 7(c)(2) of the Northwest Power Act requires that the rates to DSI customers shall not be
3 less than the rates in effect for the contract year ending June 30, 1985 (the floor rate).

4 Accordingly, a test is performed to determine if the IP rate is at a level below the 1985 IP rate.
5 If so, an adjustment is made that raises the IP rate to the floor rate and credits other customers
6 with the increased revenue from the DSIs. If the IP rate is set at a level above the floor rate, no
7 floor rate adjustment is necessary.

8
9 The first step in calculating the floor rate is to apply the IP-83 Standard rate components to rate
10 period (FY 2012-2013) DSI billing determinants. The resulting revenue figure is divided by
11 total IP rate period energy loads to arrive at an average rate in mills per kilowatthour. This rate
12 is reduced by an Exchange Cost Adjustment and a Deferral Adjustment that were included in the
13 IP-83 rate but are no longer applicable. Both adjustments are made on a mills per kilowatthour
14 basis.

15
16 In addition, the transmission component of the IP-83 rate is removed to allow a power-only floor
17 rate comparison. The floor rate is adjusted for transmission costs by subtracting total
18 transmission costs in mills per kilowatthour from the IP-83 rate in the same manner that the
19 Exchange Cost Adjustment and Deferral Adjustment are removed. The mills per kilowatthour
20 component is determined by dividing total transmission costs in the IP-83 rate by the total energy
21 billing determinants for that rate period. See Documentation Table 2.4.6.

22
23 These calculations result in an undelivered IP floor rate. The floor rate is applied to the current
24 rate period DSI billing determinants to determine floor rate revenue. Revenue at the proposed
25 IP rates is compared to the revenue at the floor rate. Because the proposed IP rate revenue is
26 greater than the floor rate revenue, no floor rate adjustment is necessary. See Documentation
27 Tables 2.4.6 and 2.4.7.

1 **2.2.3 Section 7(b)(2) Rate Protection**

2 The rate test specified in section 7(b)(2) of the Northwest Power Act ensures that BPA’s rates for
3 public body, cooperative, and Federal agency customers (collectively referred to as preference
4 customers or 7(b)(2) customers) are no higher than rates calculated using specific assumptions
5 that remove certain effects of the Northwest Power Act. For BP-12 rates, the rate test was
6 performed in the assessment of the 2012 REP Settlement. The Settlement was found to be in
7 compliance with the rate test and rates are established pursuant to the Settlement.

8
9 **2.3 Rate Design Step**

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

17
18 **2.3.1 Description of Rate Design Step Modeling**

19 Based on the results of the Rate Directives Step, RAM2012 designs rates for each rate pool. For
20 the PFp Melded rate, the PFx rate, the IP rate, and the NR rate, the rate design can be applied
21 without further processing. The design of the PFp Melded rate is described in section 3.1.12.
22 The design of the PFx rate is described in section 3.2. The design of the IP rate is described in
23 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

1 are allowed to forgo purchasing at Tier 2 rates and have this load served at the Load
2 Shaping rate.)

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

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

12 **2.3.2 PF Public Rate Design Step for Tiered Rates**

13 The rate design for the PFp rate is established in the TRM. The TRM specifies that all costs and
14 credits comprising BPA's total power revenue requirement be allocated to one of four Customer
15 Charge cost pools: Composite, Non-Slice, Slice, or Tier 2. The Tier 2 cost pool is further
16 divided into Short-Term and Load Growth cost pools. After reflecting the cost allocations to
17 other rate pools, the end result of the TRM cost allocations is that the total costs allocated to the
18 four Customer Charge cost pools will equal the total costs allocated to the PFp rate pool in the
19 COSA Step and the Rate Directives Step. Thus, the TRM cost allocations neither increase nor
20 decrease the cost allocations to the PFp rate pool after the Rate Directives Step. A demonstration
21 of this equivalence is shown in Documentation Table 2.5.5.4.

22
23 While the TRM cost allocations do not change the costs allocated to the PFp rate pool, they do
24 assign cost responsibility to the rates paid by customers purchasing the three primary products
25 offered in the CHWM contracts: Slice/Block, Load Following, and Block. In addition, the TRM
26 cost allocations also recognize that, even though the ratesetting methodology described in this

1 section 2 is performed as if the REP is an actual purchase and sale of power, at this point in the
2 ratesetting process the PFp rate can be determined based on its allocated share of the total REP
3 benefit costs, rather than exchange resource costs and PFX revenues.
4

5 **2.3.2.1 Composite Cost Pool**

6 Except for costs and credits that are distinctly associated with a particular primary product, all
7 Tier 1 costs and credits are allocated to the Composite cost pool. The Composite cost pool forms
8 the cost basis for the Composite Customer rate, which is paid by all preference customers with a
9 CHWM contract.
10

11 **2.3.2.2 Non-Slice Cost Pool**

12 Tier 1 costs and credits, primarily secondary revenues, that are not associated with the Slice
13 product are allocated to the Non-Slice cost pool. The Non-Slice cost pool forms the cost basis
14 for the Non-Slice Customer rate, which is paid by preference customers that have selected the
15 Load Following product or the Block product; it is also paid by customers selecting the
16 Slice/Block product for their Block purchases.
17

18 **2.3.2.3 Slice Cost Pool**

19 Tier 1 costs and credits that are associated with the Slice product are allocated to the Slice cost
20 pool. The Slice cost pool forms the cost basis for the Slice Customer rate, which is paid by
21 preference customers that have selected the Slice/Block product for their Slice purchases. In the
22 BP-12 rates there are no costs allocated to this cost pool.
23

24 **2.3.2.4 Tier 2 Cost Pools**

25 Costs and credits that are associated with the sale of power to serve a customer's Above-RHWM
26 load are allocated to Tier 2 cost pools. Generally, the costs allocated to a Tier 2 cost pool are

1 purchase power costs designated by BPA as being for this purpose. In addition to purchase
2 power costs, Tier 2 rates are established to recover Resource Support Services, overhead, and
3 other BPA costs that are not necessarily incurred solely for the purpose of serving Above-
4 RHWM load, but are supportive in part of making such sales. The initial allocation of these
5 other costs is to either the Composite cost pool or the Non-Slice cost pool. Therefore, the
6 portion of the revenues expected to be received from sales at a Tier 2 rate is reassigned to the
7 cost pool where the initial allocation is made. See Documentation Table 2.5.5.2.

8

9 **2.4 Rate Modeling Iterations**

10 Several iterations—both internally within RAM2012 and externally between other models and
11 RAM2012—are required before the ratesetting process is finalized. These iterations ensure that
12 the appropriate costs are computed and allocated consistent with the principles of the Northwest
13 Power Act and TRM rate design.

14

15 **2.4.1 Iterations Internal to the Model**

16 **2.4.1.1 Participation in the Residential Exchange Program**

17 Participation in the REP requires that the applicable Base PFX rate is less than a participant's
18 Average System Cost. The applicable Base PFX rate is either the Base Tier 1 PFX rate for COUs
19 or the untiered Base PFX rate for IOUs. If a utility has an ASC less than its applicable Base PFX
20 rate, that utility is ineligible to participate in the REP. RAM2012 uses a macro loop feature to
21 test whether, for each year of the exchange period, each utility with an ASC qualifies for the
22 REP. If a utility does not qualify, a binary index is used to exclude it, and if it does qualify, the
23 index is set to include it. This test is done such that the exchange resource costs are calculated
24 including the resources purchased from only REP participants, and before the Rate Directives
25 Step of the 7(c)(2) linking of the IP and PF rates, the determination of rate protection, and
26 subsequent reallocation of rate protection.

1 **2.4.1.2 Costs of Rate Discounts**

2 The costs of the LDD and IRD (see sections 2.1.3.3 and 2.1.3.4) are mathematically related to
3 Composite, Non-Slice, and Slice customer charges, and these charges are dependent on REP
4 benefits and IP and NR revenues. LDD and IRD costs are indeterminate until final charges are
5 set; however, since final charges are in part dependent upon the costs associated with these other
6 factors, iteration in the model is necessary. As explained in sections 2.1.3.3 and 2.1.3.4,
7 RAM2012 computes the cost of the LDD based on offset quantities and the IRD rate based on a
8 historical percentage, which are applied to internally computed customer charges. For each
9 iteration of the model, the appropriate charges are applied, and new discount costs are computed.
10 These new discount costs are allocated in the COSA Step, and the Rate Directives Step and TRM
11 Step are performed again. New charges and rates are computed, which are again applied to the
12 discount calculations. The iterative process continues until convergence.

13
14 **2.4.1.3 Contract Formula Rates**

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

18
19 **2.4.2 Iterations External to the Model**

20 Some aspects of the ratesetting process are dependent upon the rates computed in RAM2012.
21 Many of these dependencies have been integrated within RAM2012, as described above. Other
22 dependencies are simply too large to incorporate into one model. Thus, external iterations must
23 be performed before rates can be finalized.

1 **2.4.2.1 Consumer-Owned Utility Average System Costs**

2 The ASCs of COUs participating in the REP are based in part on the cost of power purchased
3 from BPA at rates determined in RAM2012. In addition, the amount of Refund Amount that the
4 COU will receive is also dependent upon the COU's TOCA. These two factors require a
5 recomputation of ASCs for COUs based on the PFp rate level and the Refund Amount. This
6 iteration is manually performed between RAM2012 and the ASC forecast model. Revised ASCs
7 are included in RAM2012, and rate levels are recomputed until the results converge.
8

9 **2.4.2.2 Risk Analysis and Mitigation: PNRR**

10 PNRR is an amount of net revenues required from power rates to ensure that cash flows from
11 proposed rates meet BPA's Treasury Payment Probability (TPP) standard. The amount of PNRR
12 is the result of an iterative process among four models: RAM2012, RiskMod, NORM, and
13 ToolKit. See Power Risk and Market Price Study section 3.3. The iterative process is initiated
14 with a seed value for PNRR in revenue requirement used in RAM2012. The resultant rates are
15 used in RiskMod and NORM to produce distributions of net revenues. These distributions are
16 then used in the ToolKit to produce a new PNRR value for the RAM2012 revenue requirement.
17 See Documentation section 2. Because PNRR is determined to be zero, no iterative process is
18 required to determine rate levels for the BP-12 rates.
19

20 **2.4.2.3 Revised Revenue Test**

21 The revenue forecast quantifies the expected level of sales and revenue from power rates and
22 other sources for the rate period, FY 2012-2013. Two revenue forecasts are prepared, one with
23 current rates and the other with proposed rates. These forecasts are used to test whether current
24 rates will recover the generation revenue requirement and, if not, whether proposed rates are
25 sufficient to recover the generation revenue requirement. The revenue test is described in
26 section 4 of this Study and in the Power Revenue Requirement Study, section 3.3. The power

1 rates placed in effect October 1, 2010, are used in the calculation of revenue at current rates for
2 FY 2012-2013, using the load forecast from the Power Loads and Resources Study.

3
4 The rates as computed in RAM2012 are applied to the same loads to create a revenue forecast at
5 proposed rates for FY 2012-2013. The revenue from this forecast is shown in Documentation
6 Table 4.2. These revenues are incorporated into the revenue test in the Power Revenue
7 Requirement Study, section 4, to determine if the proposed rates are sufficient to recover the
8 revenue requirement. If the rates are not sufficient, an adjustment to the rates is required to
9 increase the rates to a level sufficient to recover the revenue requirement.

10
11 The revised revenue test demonstrates that the BP-12 rates are sufficient to recover the revenue
12 requirement, and no further rate adjustment is needed. See Power Revenue Requirement Study
13 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

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

4
5 The PFp rate design is based on the design set forth in the Tiered Rate Methodology, BP-12-
6 A-03. The TRM established a rate design for the PFp rate schedule to be used for power sales
7 under BPA's CHWM contracts.

8
9 The PFx rate schedule is also described in this section. Due to the annual design of the
10 Residential Exchange Program, application of a rate design that included rate differentiation
11 within the PFx rate schedule for peaking capacity use, time-of-day use, and seasonal use of
12 power purchased from BPA was deemed unnecessary for the PFx rate schedule.

13
14 The TRM did not establish a rate design for the PFx, IP, and NR rate schedules. The rate design
15 for IP and NR service is described in this Study, and the specific rates are set forth in the Power
16 Rate Schedules, BP-12-A-02B. Certain PFp design elements adopted in the TRM are used in the
17 IP-12 and NR-12 rate design, in particular the method for scaling Energy rates from the market
18 forecast and the general method for calculating the Demand billing determinant.

19 20 **3.1 Priority Firm Public Rate Design**

21 As described in the TRM, the PFp rate design includes two tiers. The tiering of the rates is a
22 ratemaking construct that allocates the costs and credits functionalized to power; it is not an
23 allocation of power to customers. The costs and credits functionalized to power are allocated to
24 the Tier 1 and Tier 2 cost pools based upon the principle of cost causation. The forecast costs
25 and credits allocated to Tier 1 cost pools are kept separate and distinct from those allocated to the
26 Tier 2 cost pools.

1 In addition to creating the Tier 1 and Tier 2 cost pools, the TRM also determined a new rate
2 design for the Tier 1 rates. Tier 1 rates include three customer charges: the Composite Customer
3 Charge, the Non-Slice Customer Charge, and the Slice Customer Charge. These charges recover
4 the costs allocated to their respective cost pools. The rate for each of the customer charges is a
5 dollar amount per each one percentage of the billing determinant. For each customer charge,
6 each customer's billing determinant will respectively be its Tier 1 Cost Allocator (TOCA), Non-
7 Slice TOCA, or Slice Percentage. In addition to the customer charges, the Tier 1 rates include
8 24 monthly/diurnal Load Shaping rates and a Demand Charge with 12 monthly Demand rates.

9
10 Tier 2 rates coincide with the Tier 2 rate options elected by customers to meet their Above-
11 RHWM Load obligation. In PF-12 these are the Short-Term and Load Growth Tier 2 rates.

12
13 BPA calculated two other rates based on the TRM "component" rates. First is the PFp Tier 1
14 Equivalent Rate for use in contracts that have rates that are tied to a traditional PF HLH/LLH
15 rate design. Second, a PFp Melded rate schedule is included should BPA need to serve load of a
16 preference customer that does not have a CHWM Contract.

17 18 **3.1.1 PFp Customer Cost Pools**

19 Under the TRM, there are three Tier 1 cost pools (Composite, Non-Slice, and Slice) and the
20 possibility of multiple Tier 2 cost pools. For the FY 2012-2013 rate period there are two Tier 2
21 cost pools, Load Growth and Short-Term. The method by which costs and credits are allocated
22 among the five PFp cost pools is directed by the TRM. Costs and credits are allocated among
23 the cost pools based on the association of the cost or credit with a product (Load Following,
24 Block, or Slice/Block) and a tier (Tier 1 or Tier 2). The Composite cost pool includes all Tier 1
25 costs and credits that are not otherwise allocated to the Slice and Non-Slice cost pools. The Slice
26 cost pool includes only those costs and credits that are specifically and uniquely attributed to the

1 Slice product. Likewise, the Non-Slice cost pool includes only those costs and credits that are
2 specifically and uniquely attributed to the Load Following and Block products (including the
3 Block portion of the Slice/Block product). The Tier 2 Load Growth and Short-Term cost pools
4 include all costs and credits that are attributable to the resources and services necessary for load
5 served at a Tier 2 rate. Additional detail on these cost pools is found in section 3.1.7 below.

6
7 To calculate the Tier 1 and Tier 2 rates, all costs and credits are allocated to the appropriate cost
8 pools; all costs functionalized to generation are allocated to one of the five PFp cost pools
9 (Composite, Non-Slice, Slice, Tier 2 Load Growth, and Tier 2 Short-Term). As described in
10 section 2.1 above, the same costs and credits have also been allocated to the PF rate pool and
11 other rate pools: IP, NR, and FPS. To account for the costs and credits allocated to these other
12 rate pools, the revenues recoverable from the other rate pools have reduced the costs allocated to
13 the Composite cost pool. A demonstration is included in RAM2012 that shows that the revenue
14 requirement allocated to the PFp rate pools in the COSA equals the costs and credits allocated to
15 the PFp cost pools after the reductions from the other rate pools. See Documentation
16 Tables 2.5.6.1 and 2.5.6.2.

17
18 Once costs and rate design revenue credits have been balanced with the revenue requirement, to
19 the extent necessary additional adjustments to the PFp cost pools are made to avoid cost shifts
20 among products (Load Following, Block, and Slice/Block), and tiers (Tier 1 and Tier 2). These
21 rate design adjustments move dollars from one cost pool to another through equal credits and
22 debits and do not change the overall revenue requirement or the cost allocations among PF, IP,
23 NR, and FPS. These rate design adjustments include three adjustments made within Tier 1
24 (section 3.1.3) and two adjustments made between Tier 1 and Tier 2 (section 3.1.4). The three
25 adjustments made within Tier 1 are the Transmission Loss Adjustment, the Firm Surplus and
26 Secondary Adjustment from Unused RHW, and the Balancing Augmentation Adjustment.
27 The two adjustments made between Tier 1 and Tier 2 are the Tier 2 Overhead Adjustment and

1 the Tier 2 Balancing Adjustment. The complete allocation of costs with all revenue credits and
2 adjustments for the five cost pools can be found in Documentation Table 2.3.5.

3 4 **3.1.2 Rate Design Revenue Credits**

5 The Composite and Non-Slice cost pools contain credits for revenues collected from other
6 components of the PFp rates. The Composite cost pool includes a credit for forecast revenue
7 collectable from the sale of Resource Support Services. The Non-Slice cost pool includes a
8 credit for forecast revenue collectable through the Load Shaping, Demand, and Resource
9 Shaping charges. All of these rate design credits are necessary to ensure that the PFp rates do
10 not overcollect the allocated revenue requirement and that the costs and credits have been
11 allocated as specified in the TRM.

12 13 **3.1.2.1 Resource Support Services (RSS) Revenue Credit**

14 BPA provides five RSS options that generate revenue from preference customers. Revenue
15 received from RSS is credited to the Composite cost pool. For transparency purposes, BPA
16 committed in the TRM to apply applicable RSS to resources serving system augmentation needs
17 (currently Klondike III) and to resources supporting the Tier 2 rates, if appropriate. In these
18 situations, the source of the RSS revenue credit to the Composite cost pool is provided either
19 through an RSS adder to the system augmentation cost or an RSS cost within a Tier 2 cost pool.

20
21 The total annual RSS revenue credit for FY 2012-2013 can be found in Documentation
22 Table 3.1.

1 **3.1.2.2 Resource Shaping Charge (RSC) Revenue Credit**

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

6
7 BPA committed in the TRM to apply RSS and the RSC to resources serving system
8 augmentation needs (Klondike III) and to resources supporting the Tier 2 rates in order to make
9 these acquisitions financially equivalent to a flat block. See TRM section 8. In these situations,
10 the source of the RSC revenue credit is provided either through an RSC adder to the system
11 augmentation cost or through an RSC adder within a Tier 2 cost pool. The forecast annual RSC
12 revenue credit for FY 2012-2013 can be found in Documentation Table 3.1.

13
14 **3.1.2.3 Load Shaping Revenue Credit**

15 The Load Shaping charge is designed to recover costs associated with shaping the firm output of
16 the Tier 1 System Resources to the monthly/diurnal shape of a customer's Tier 1 Load. The
17 Load Shaping charge is applicable to Non-Slice products, Block (including the Block portion of
18 the Slice/Block) and Load Following, but not the Slice portion of the Slice/Block product. Thus,
19 as stated in the TRM, section 5.2, forecast revenue from the Load Shaping charge is credited to
20 the Non-Slice cost pool by means of the Load Shaping Revenue Credit.

21
22 **3.1.2.4 Demand Revenue Credit**

23 The Demand charge is designed to send a price signal to a limited portion of a customer's overall
24 demand on BPA and is applicable to customers purchasing Load Following and Block with
25 Shaping Capacity products. Thus, forecast revenue from the Demand charge is credited to the
26 Non-Slice cost pool by means of the Demand Revenue Credit.

1 **3.1.3 Rate Design Adjustments Made between Tier 1 Cost Pools**

2 **3.1.3.1 Transmission Loss Adjustments**

3 The Transmission Loss Adjustments provide a credit to the Composite cost pool and an
4 equivalent debit to the Non-Slice cost pool based on Non-Slice transmission losses. The
5 Transmission Loss Adjustments account for different accounting of transmission losses to the
6 Slice/Block and non-Slice products. The non-Slice products and the Block portion of the
7 Slice/Block products are delivered to the purchaser's load service area, while the Slice product is
8 delivered to the purchaser at BPA's generation bus bar. The cost of generating the real power
9 losses for the transmission of non-Slice sales is included in BPA's revenue requirement.
10 Conversely, the cost of generating the real power losses for the transmission of Slice sales is
11 borne by the purchaser. The Transmission Loss Adjustments transfer the cost of generating the
12 real power losses for the transmission of non-Slice PF sales from the Composite cost pool to the
13 Non-Slice cost pool. The Transmission Loss Adjustments are calculated by multiplying the
14 network losses associated with the Non-Slice PF products, including the Block portion of the
15 Slice/Block product, by the Average Slice and Non-Slice Tier 1 Rate (see Documentation, Table
16 2.5.7.1). The calculation and result of the Transmission Loss Adjustments can be found in
17 Documentation Table 2.5.3.

18
19 **3.1.3.2 Firm Surplus and Secondary Adjustments from Unused RHW**

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

23
24 Unused RHW reduces the need for system augmentation and/or increases firm power available
25 for sale in the market. The reduced augmentation expenses and/or increased firm power market
26 revenues are reflected in three lines on the TRM cost table (1) Augmentation Power Purchases;
27 (2) Secondary Revenue; and (3) Balancing Purchases. See Documentation Table 2.5.1. The

1 Augmentation Power Purchases line is part of the Composite cost pool while the Secondary
2 Revenue and Balancing Purchases are part of the Non-Slice cost pool. In order to share the
3 entire benefit of Unused RHW M to all customers, both the Composite and Non-Slice cost pools
4 contain a Firm Surplus and Secondary Adjustment (from Unused RHW M), with one reflecting a
5 credit and the other an equal debit.

6
7 The Firm Surplus and Secondary Adjustments have two purposes. One purpose is to reflect the
8 difference between the value of a flat annual block of system augmentation and the value of the
9 Unused RHW M when the Unused RHW M displaces augmentation. The difference between a
10 flat annual block of system augmentation and the shape of the Unused RHW M is reflected in
11 changes in the assumed balancing purchases and associated costs. These changes in balancing
12 purchase costs are captured in the Non-Slice cost pool. A Firm Surplus and Secondary
13 Adjustment reallocates this change in balancing purchase costs associated with this difference in
14 value from the Non-Slice cost pool to the Composite cost pool.

15
16 The second purpose of the Firm Surplus and Secondary Adjustments is to reflect the full value of
17 the Unused RHW M when the Unused RHW M creates firm surplus power. The revenue
18 associated with this change in firm surplus power related to the Unused RHW M is reflected in
19 the secondary revenue credit in the Non-Slice cost pool. A Firm Surplus and Secondary
20 Adjustment reallocates this change in secondary revenues associated with the Unused RHW M
21 from the Non-Slice cost pool to the Composite cost pool.

22
23 The value of Unused RHW M consists of portions of RHW M Augmentation, Tier 1 System Firm
24 Critical Output, and an associated portion of secondary energy. Each of these three components
25 is valued at its respective price: the Augmentation price for the RHW M Augmentation
26 component, the market price (as expressed by the Load Shaping rates) for the Tier 1 System
27 Firm Critical Output component, and the market price (as expressed by the average price

1 received for secondary sales) for the secondary component. The value of Unused RHWM
2 (expressed in dollars per megawatthour) also will be calculated for use in the Slice True-Up of
3 the Firm Surplus and Secondary Adjustment line item in the Composite cost pool.
4

5 See Table 2.5.2 of Documentation for results and calculation of the Firm Surplus and Secondary
6 Adjustments from Unused RHWM and the dollar per megawatthour Slice True-Up value of
7 Unused RHWM.
8

9 **3.1.3.3 Balancing Augmentation Load Adjustments**

10 Balancing augmentation load is either (1) Above-RHWM load that is forecast to be served at
11 Load Shaping rates, rather than at Tier 2 rates or with a non-Federal resource (net positive load
12 shaping billing determinants) or (2) load that is forecast to be served at Tier 2 rates or with a
13 non-Federal resource, rather than at the appropriate Tier 1 rates (net negative load shaping billing
14 determinants).
15

16 The first condition occurs when Above-RHWM load is forecast to be served at load shaping
17 rates either when a Load Following customer's annual Above-RHWM load is less than 8,760
18 MWh and the Load Following customer made no alternative election to serve its Above-RHWM
19 load, or when Above-RHWM load is locked down and the load forecast is updated during the
20 rate case to reflect the forecast of a larger load.
21

22 The second condition occurs when load that would otherwise be served at Tier 1 rates is served
23 at Tier 2 rates or with a non-Federal resource when Above-RHWM load is locked down and the
24 load forecast is updated during the rate case to reflect the forecast of a smaller load.
25

1 When the first condition exists and the amount of system augmentation purchases is equal to or
2 greater than the amount of balancing augmentation load, the acquisition costs attributable to
3 supplying balancing augmentation load are included as a system augmentation expense in the
4 Composite cost pool. The revenue from supplying balancing augmentation load is credited to
5 the Non-Slice cost pool through the Load Shaping charge revenue credit. Without a Balancing
6 Augmentation Load Adjustment, only Non-Slice customers would receive a credit through an
7 increased Load Shaping Charge revenue credit, but both Slice and Non-Slice customers would
8 bear the cost of an increased system augmentation expense. The Balancing Augmentation Load
9 Adjustment corrects this inequity with a credit to the Composite cost pool and an equal debit to
10 the Non-Slice cost pool.

11
12 When the second condition exists, there is a reduction in system augmentation expenses from
13 what would have otherwise occurred. The Composite Cost Pool would have received an implicit
14 reduction in costs due solely to load variation attributable to Non-Slice customer loads. In this
15 case, the Balancing Augmentation Adjustment is a debit to the Composite Cost Pool and an
16 equal credit to the Non-Slice Cost pool.

17
18 In the first condition, the sum of Load Shaping billing determinants is positive. The Balancing
19 Augmentation Load Adjustments to the Composite and Non-Slice cost pools are calculated as
20 the lesser of the sum of the Load Shaping billing determinants for each fiscal year or the
21 augmentation amount for each fiscal year. The result is multiplied by the augmentation price for
22 the respective fiscal year. In the second condition, the sum of the Load Shaping billing
23 determinants is negative. The Balancing Augmentation Load Adjustments to the Composite and
24 Non-Slice cost pools are calculated as the greater of the sum of the Load Shaping billing
25 determinants for each fiscal year or the avoided augmentation amount for each fiscal year. The
26 result is multiplied by the augmentation price for the respective fiscal year.

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

6 **3.1.4 Rate Design Adjustments Made Between Tier 1 and Tier 2 Cost Pools**

7 **3.1.4.1 Tier 2 Overhead Adjustment**

8 The Tier 2 Overhead Adjustment credits the Composite cost pool for the overhead costs charged
9 to the Tier 2 cost pools. Each of the Tier 2 cost pools includes an Overhead Cost Adder, which
10 reflects a proportionate share of BPA's total overhead costs. See section 3.1.7.1. The Tier 2
11 Overhead Adjustment credited to the Composite cost pool is equal to the sum of the Overhead
12 Cost Adders charged to all of the Tier 2 cost pools. This Tier 2 Overhead Adjustment for
13 FY 2012-2013 can be found in Documentation Table 3.2.

15 **3.1.4.2 Tier 2 Balancing Adjustments**

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

21
22 When Tier 2 purchases exceed (or are less than) Tier 2 load obligations (Tier 2 imbalance), a
23 credit (or debit) is applied to the applicable Tier 2 cost pool, and an equal debit (or credit) is
24 applied to the Composite cost pool, the Non-Slice cost pool, or a combination of the Composite
25 and Non-Slice cost pools. The respective credits and debits are calculated by multiplying either
26 the annual augmentation price or the flat annual equivalent of the AURORA market price

1 forecast for each fiscal year (see Power Risk and Market Price Study Documentation, Table 17)
2 by the difference between sales at the Tier 2 rate and the megawatthours purchased to meet that
3 load. The augmentation price is used in the calculation when the Tier 2 imbalance changes the
4 amount of augmentation expense included in the Composite cost pool. Conversely, the
5 AURORA market price is used when the Tier 2 imbalance changes the amount of firm surplus in
6 the Non-Slice cost pool. See Documentation Table 3.3 for the flat annual equivalent of the
7 AURORA market price forecast, the annual augmentation price, and the annual augmentation
8 amount. Both the Composite and Non-Slice cost pools can be credited or debited if there is a
9 Tier 2 imbalance and the total amount of augmentation is less than the Tier 2 imbalance.

10
11 Due to a zero augmentation amount in FY 2012 and a positive augmentation amount in FY 2013,
12 the Tier 2 Balancing Adjustment impacts the firm surplus amount in FY 2012 and the
13 augmentation amount in FY 2013. Therefore, the AURORA market price was used to calculate
14 the Tier 2 Balancing Adjustment for FY 2012, and the annual augmentation price was used to
15 calculate the Tier 2 Balancing Adjustment for FY 2013. See Documentation Table 3.2.

16 17 **3.1.5 PFp Tier 1 Billing Determinants**

18 **3.1.5.1 Tier 1 Cost Allocator**

19 The majority of BPA's costs to be collected through PF rates are allocated among customers
20 through the TOCA. The TOCA is the customer-specific billing determinant used to collect the
21 costs allocated to the Composite cost pool. A TOCA is calculated for each fiscal year of the rate
22 period for each PFp customer. Each customer's annual TOCA is calculated as a percentage by
23 dividing the lesser of an individual customer's RHW or its Forecast Net Requirement by the
24 total of the RHWs for all PFp customers. The TOCA is a percentage rounded to 5 decimal
25 places, i.e., seven significant digits.

1 The Forecast Net Requirement and RHWMM for the individual customer and the sum of RHWMMs
2 for all customers are expressed in average annual megawatts and rounded to three decimal
3 places. The total of the RHWMMs for all customers can be found in Table 1, and the sum of
4 TOCAs used for FY 2012-2013 can be found in Documentation Table 2.5.5.3.

6 **3.1.5.2 Non-Slice TOCA**

7 The Non-Slice TOCA is the billing determinant that is used to collect the costs allocated to the
8 Non-Slice cost pool. A Non-Slice TOCA is calculated for each PFp customer for each year of
9 the rate period. The Non-Slice TOCA is equal to a customer's TOCA if the customer is
10 purchasing the Load Following or Block product. The Non-Slice TOCA for customers
11 purchasing the Slice/Block product is computed as the difference between the customer's TOCA
12 and its Slice Percentage. The Non-Slice TOCA percentage is rounded to 5 decimal places. The
13 forecast sum of Non-Slice TOCAs used for FY 2012-2013 can be found in Documentation
14 Table 2.5.5.3.

16 **3.1.5.3 Slice Percentage**

17 The Slice Percentage is the billing determinant used to collect the costs allocated to the Slice cost
18 pool. A Slice Percentage is calculated for each year of the rate period for each PFp customer
19 purchasing the Slice/Block product. The Slice Percentage in Exhibit K of each Slice customer's
20 CHWM contract is updated each year and can be adjusted, pursuant to section 3.6 of the TRM.
21 The Slice Percentage is rounded to 5 decimal places.

23 **3.1.5.4 Load Shaping Billing Determinant**

24 The billing determinant for the Load Shaping charge reflects the difference between a customer's
25 actual load served at Tier 1 rates and the customer's annual load reshaped into the

1 monthly/diurnal shape of RHWMTier 1 System Capability (System Shaped Load). The Load
2 Shaping billing determinant can have either a positive or a negative value.

3
4 A customer's System Shaped Load is calculated as the RHWMTier 1 System Capability (see
5 section 1.6) for each of the 24 monthly/diurnal periods of the fiscal year multiplied by the
6 customer's Non-Slice TOCA. The Load Shaping billing determinants are calculated as the
7 amount of a customer's monthly/diurnal electric load (measured in kilowatthours) to be served at
8 Tier 1 rates less the customer's System Shaped Load for the same monthly/diurnal period.

9
10 **Monthly/Diurnal RHWMTier 1 System Capability.** The TRM specifies that the
11 monthly/diurnal shape of the RHWMTier 1 System Capability will be used to compute the
12 System Shaped Load for purposes of computing Load Shaping billing determinants. This shape
13 is computed to be constant across both years of the rate period and is the average of each year's
14 respective monthly/diurnal megawatthour amount. In a rate period that does not include a leap
15 year, there will be 24 monthly/diurnal amounts for the RHWMTier 1 System Capability
16 specified in the GRSPs. In a rate period that includes a leap year, there will be 26 amounts,
17 because each February has a unique value for each HLH and LLH period. See GRSP II.Q.

18 19 **3.1.5.5 Demand Billing Determinant**

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

24
25 Four quantities are used in calculating a PFp customer's Demand charge billing determinant:
26 (1) the Tier 1 Customer's System Peak (CSP); (2) the average amount of a customer's electric

1 load (measured in average kilowatts) that was served at Tier 1 rates during the Heavy Load
2 Hours of a month; (3) the customer's Contract Demand Quantity (CDQ, expressed in kilowatts);
3 and (4) any applicable Super Peak Credit as specified in a customer's CHWM contract.

4
5 The Demand billing determinant is determined by calculating a customer's CSP and then
6 subtracting the other three quantities. The Demand billing determinant calculation can never
7 result in a negative billing determinant. That is, if the calculation results in a value less than
8 zero, the billing determinant is deemed to be zero.

9
10 Tier 1 CSP is equal to a customer's maximum Actual Hourly Tier 1 Load (measured in
11 kilowatts) during the Heavy Load Hours of a month.

12
13 Twelve CDQs are specified for each PFp customer in the customers' CHWM contract.

14
15 The Super Peak Credit will be determined pursuant to a customer's CHWM contract. The Super
16 Peak Period hours for FY 2012-2013 are defined in the GRSPs as follows (HE = Hour Ending):

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

20 21 **3.1.6 PFp Tier 1 Rates**

22 **3.1.6.1 Tier 1 Customer Rates**

23 Rates for the Composite, Non-Slice, and Slice customer charges are expressed as dollars per one
24 percentage point of billing determinant (TOCA, Non-Slice TOCA, or Slice Percentage,
25 respectively). Each of the three rates is calculated by dividing the total costs allocated to each
26 cost pool by the sum of the respective forecast billing determinants. The quotient of that

1 calculation is then divided by 12 to yield a monthly rate per one percent of the applicable billing
2 determinant.

3
4 The monthly rates for each of the Tier 1 cost pools are shown in Documentation Table 2.5.5.3.

6 **3.1.6.2 Tier 1 Load Shaping Rates**

7 The PFp rate design includes 24 Load Shaping rates (two diurnal periods—HLH and LLH—for
8 each of 12 months). The Load Shaping rates are set equal to the rate period average marginal
9 cost of power for each monthly/diurnal period as determined in the Power Risk and Market Price
10 Study, section 2.4. Also see Documentation Table 3.4.

12 **3.1.6.2.1 Load Shaping True-Up**

13 The Load Shaping True-Up is an adjustment to the Load Shaping charge and is necessary to
14 ensure that each customer pays a Tier 1 rate for purchases of energy that are less than its
15 RHW. At the end of each fiscal year for each Load Following customer, BPA will calculate
16 whether a true-up of the Load Shaping charge will be applicable. The Load Shaping Charge
17 True-Up applies to a Load Following customer when either its TOCA Load or its Actual Annual
18 Tier 1 Load is less than its RHW. The Load Shaping True-Up rate is the difference between
19 (1) the system-weighted average of the Load Shaping rates and (2) the Composite Customer rate
20 plus the Non-Slice Customer rate, converted to mills per kilowatt-hour. The detailed process for
21 calculating the Load Shaping True-Up rate is set forth in section 5.2.4.2 of the TRM, and the rate
22 is specified in GRSP II.I.

23
24 **Special Implementation Provision for Load Shaping True-Up.** Special implementation
25 provisions apply if two conditions are met: (1) a customer has Above-RHW load, and (2) the
26 customer has unused RHW greater than zero. If these conditions are met, the customer may be

1 eligible for an additional Load Shaping True-up credit. The amount of the additional Load
2 Shaping True-up credit will depend on a second calculation.

3
4 This special implementation provision is designed to solve a transitional implementation issue
5 caused by setting Above-RHWM load based on a different forecast than is used to determine a
6 customer's TOCA. This implementation provision is necessary in this rate period because
7 Above-RHWM Load was determined in 2009 and the calculation of a customer's TOCA
8 occurred in 2011. A consequence of using forecasts prepared at different times is the possibility
9 that a customer has both Above-RHWM Load and unused RHWM. This cannot happen if the
10 same forecast is used to set both Above-RHWM Load and customers' TOCAs.

11
12 First, if the Annual Deviation calculation of the Load Shaping Charge True-up is negative or
13 equal to zero and the absolute value of the Annual Deviation is less than the customer's Above-
14 RHWM Load, then the additional credit is equal to the Load Shaping True-up rate multiplied by
15 (1) the customer's Above-RHWM load, or (2) the Above-RHWM load less the absolute value of
16 the Annual Deviation amount, or (3) the Above Forecast amount, whichever is the smallest.

17 Second, if the Annual Deviation calculation of the Load Shaping Charge True-up is positive and
18 the Annual Deviation amount is less than the Above Forecast amount, then the additional credit
19 is equal to the Load Shaping True-up rate multiplied by the lesser of (1) the customer's Above-
20 RHWM load or (2) the Above Forecast amount less the Annual Deviation amount.

21 22 **3.1.6.3 Tier 1 Demand Rates**

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

1 LMS-100 with a 2012 in-service date. The all-in capital cost under these specifications is
2 \$1,081/kW. See Documentation Table 3.5.

3
4 The projected debt payment on the \$1,081/kW fixed capital costs is estimated at \$115.48/kW/yr,
5 based on a cost of debt of 4.71 percent financed over 30 years. The plant is assumed to be
6 owned by a publicly owned utility with BPA-backed bonds. The cost of debt is estimated with
7 BPA's FY 2012 Third-Party Tax-Exempt 30-Year Borrowing Rate Forecast. See FY 2011
8 Common Agency Assumptions memo in the Power Revenue Requirement Documentation,
9 chapter 6.

10
11 The cost of fixed O&M included in the Demand rate calculation is obtained from the Microfin
12 model. The calculation of the Demand rate uses the Microfin model's 2006 estimate of
13 \$8/kW/yr and is escalated to 2012 and 2013 dollars using the 2005 to 2010 average (5-year) rate
14 of 2.05 percent calculated from the Implicit Price Deflators from the U.S. Bureau of Economic
15 Analysis. The two-year average annual cost for fixed O&M is \$9.12/kW/yr.

16
17 Insurance and fixed fuel are also included in the calculation of the Demand rate. The annual
18 insurance cost of \$2.61/kW/yr is calculated based on 0.25 percent of the mid-year assessed value
19 obtained from the Council's Microfin model. The fixed fuel cost assumed in the Demand rate
20 calculation is \$35.73/kW/yr. The fixed fuel cost is estimated using Microfin's vintaged heat rate
21 of 8,738 Btu/kWh and applied to the average of the existing and new Pacific Northwest East
22 (PNWE) fixed fuel costs for the applicable fiscal year. Lastly, an offsetting revenue credit was
23 applied equal to 10 percent for the resale of firm pipeline rights.

24
25 The average annual expense is \$115.48/kW. This annual value is shaped into the 12 months of
26 the year using the shape of the Load Shaping rates, resulting in Demand rates specific to each

1 month. See Documentation Table 3.5 and the Power Rate Schedules, BP-12-A-02B, *e.g.*,
2 section 2.1.2.1.

3 4 **3.1.6.4 PFp Tier 1 Equivalent Rates**

5 The PFp Tier 1 Equivalent rates consist of 12 HLH and 12 LLH Energy rates and 12 Demand
6 rates. The PFp Tier 1 Equivalent Energy rates are equal to the Load Shaping rates less a single
7 \$/MWh value. The single \$/MWh value scales the Load Shaping rates to a level at which the
8 PFp Tier 1 Equivalent Energy rates, in conjunction with the demand revenue, would collect the
9 Tier 1 revenue requirement allocated to the PFp non-Slice loads (the Composite cost pool plus
10 the Non-Slice cost pool). This single \$/MWh value is equivalent to the Load Shaping True-Up
11 rate. This calculation can be found in Documentation Table 2.5.7.5. The Demand rates are
12 equal to the Tier 1 Demand rates.

13 14 **3.1.7 PFp Tier 2 Cost Pool**

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

21 22 **3.1.7.1 Tier 2 Overhead Cost Adder**

23 Section 6.3.3 of the TRM describes an Overhead Cost Adder to be included as part of the Tier 2
24 rates. The overhead cost components used to calculate the Tier 2 Rate Overhead Cost Adder are
25 listed in Documentation Table 3.6. The rate period total of these overhead costs is divided by
26 BPA's total forecast of revenue-producing (PFp, IP, NR, FPS, Downstream Benefits and

1 Pumping Power, Pre-Subscription, Generation Inputs for Ancillary and Other Services Revenue,
2 and Secondary sales) energy sales, which results in a \$1.17/MWh adder for the rate period. The
3 \$/MWh value in each year is multiplied by the amount of planned sales in each year for each
4 Tier 2 alternative (Short-Term and Load Growth) to produce a dollar value for the Overhead
5 Cost Adder included in each cost pool for each year. The Tier 2 Overhead Cost Adder provides
6 the revenue credit to the Composite cost pool (called Tier 2 Overhead Adjustment); see
7 section 3.1.4.1 above. The specific cost and sales values used in these calculations can be found
8 in Documentation Table 3.2.

9 10 **3.1.7.2 Tier 2 Transmission Scheduling Service Cost Adder**

11 A cost for Transmission Scheduling Service (TSS) is added to each Tier 2 cost pool. A TSS
12 Adder is calculated by dividing the operations scheduling costs for the rate period by the total
13 megawatthours actually scheduled in FY 2009 and FY 2010 to produce a yearly \$/MWh value.
14 This calculation is summarized in Table 3.3 of the Documentation. Inputs to this calculation are
15 also included in Documentation Table 3.7. This value is multiplied by the amount of planned
16 Tier 2 sales in each year for each Tier 2 alternative (Short-Term and Load Growth) to produce
17 the annual cost value for the TSS Cost Adder included in each cost pool for each year. The
18 Tier 2 TSS Cost Adder is one of the credits to the Composite cost pool summed in the Resource
19 Support Services Revenue Credit; see section 3.1.2.1 above. The calculated costs assigned to
20 each cost pool in each year can be found in Documentation Tables 3.8 and 3.9.

21 22 **3.1.7.3 Tier 2 BPA Market Purchases**

23 BPA made a total of three purchases for Tier 2 rate service for the FY 2012-2013 rate period.
24 The power amounts are roughly equal to the Tier 2 load obligation for each year plus the real
25 power losses required to deliver the power to the purchasers. Purchase costs for FY 2012 are
26 allocated entirely to the Short-Term cost pool. Purchase costs for FY 2013 are allocated on a pro

1 rata load basis between the two Tier 2 cost pools for FY 2013. The average megawatt amounts
2 and their associated power purchase prices are summarized in Documentation Table 3.10.

3 4 **3.1.7.4 Tier 2 Risk Analysis**

5 The risk analysis for Tier 2 rate service is addressed in the Power Risk and Market Price Study,
6 section 4.3. Consistent with that discussion, no risk mitigation treatment is added to the Tier 2
7 cost pools to cover risks in the FY 2012-2013 rate period.

8 9 **3.1.8 PFp Tier 2 Billing Determinants**

10 The Tier 2 billing determinant is equal to each customer's commitment to purchase from BPA all
11 or a portion of its Above-RHWM load. Each customer's Tier 2 rate service amount is
12 contractually established for FY 2012-2013, as summarized in Table 3.11 of the Documentation.
13 Because there are no purchases of Load Growth service in FY 2012, no costs are allocated to the
14 Load Growth cost pool for FY 2012.

15 16 **3.1.9 Tier 2 Rates**

17 Based on the annual average megawatt load obligations for each Tier 2 rate alternative (Short-
18 Term and Load Growth) in each year and the costs for each cost pool in each year, Tier 2 rates
19 are calculated as summarized in Documentation Tables 3.9 and 3.10. Each rate is calculated by
20 dividing the annual costs allocated to the specific Tier 2 cost pool by the billing determinants in
21 that same fiscal year. A specific Tier 2 rate in each year for each Tier 2 rate alternative is
22 necessary because there are different sets of customers associated with each rate, different costs
23 from the separate purchases, different allocations to Tier 2 cost pools, and different
24 surplus/deficit calculations (Tier 2 Balancing Adjustment).

1 **3.1.9.1 Tier 2 Rate Transmission Curtailment Management Service (TCMS) Adjustment**

2 The Tier 2 rate schedule includes an adjustment for TCMS-related costs, if a transmission event
3 (in the form of either a planned transmission outage or a transmission curtailment) has occurred
4 along the transmission path between Mid-C and the BPA Power Services point of delivery for
5 the market purchases allocated to the Tier 2 cost pools. The adjustment is described in GRSP
6 I.I.S.

7
8 **3.1.10 Calculating Charges to Reduce Tier 2 Purchase Amounts**

9 Section 2.4.2 of Exhibit C of the Load Following CHWM contract provides customers with an
10 opportunity to reduce the purchase amounts supplied by BPA at the Tier 2 Short-Term rate, if
11 notice is provided by October 31 of a Rate Case Year, which was October 31, 2010, for the BP-
12 12 rate period. If a customer makes this election, BPA may levy charges to cover costs that BPA
13 is obligated to pay and is not able recover through other transactions. Section 2.4.2.1 of the
14 contract states that BPA shall determine the costs, if any, to be collected from such charges
15 during the 7(i) Process following a customer's notice to reduce its Tier 2 rate purchase amount.
16 Two customers elected to reduce their Short-Term rate purchase amounts for the FY 2012-2013
17 period, and one customer elected to reduce its Short-Term rate purchase amounts in FY 2013.
18 This amounted to 0.166 aMW of total reduced service in FY 2012 and 0.792 aMW in FY 2013.
19 The notices were provided prior to BPA making any purchases to meet its Short-Term rate load
20 obligations, so BPA has not incurred any costs due to these purchase reductions, and therefore
21 there are no costs that need to be recovered through such charges.

22
23 **3.1.11 PFp Irrigation Rate Discount**

24 The Irrigation Rate Discount is a discount to the PFp Tier 1 rates for eligible irrigation load
25 served by a customer. The discount will appear as a credit on customer bills as an offset to the
26 charge of eligible irrigation load at Tier 1 rates. This discount is available to eligible loads
27 during May, June, July, August, and September during the BP-12 rate period. See GRSP II.H.

1 **3.1.11.1 Irrigation Rate Discount Rate**

2 The TRM establishes the method for calculating the IRD rate. The process begins with a fixed
3 Irrigation Rate Mitigation Program (IRMP) percentage equal to one minus the ratio of (1) the
4 sum of the IRMP participants' estimated charges at the FPS rates paid under IRMP for FY 2009
5 to (2) the sum of the IRMP participants' estimated charges that would have occurred under May
6 through August HLH and LLH PF-07 Energy rates for FY 2009 adjusted for any applicable
7 discounts such as the LDD. See TRM, BP-12-A-03, at section 10.3. See Documentation Tables
8 3.12 and 3.13.

9
10 The IRMP percentage is multiplied by the sum of the forecast revenue that irrigation loads will
11 pay through the composite Customer Charge, the Non-Slice Customer Charge, and the Load
12 Shaping Charge, adjusted for any applicable Low Density Discount, divided by the sum of the
13 irrigation loads (expressed in MWh), to derive a dollars per MWh discount. The applicable Low
14 Density Discount is calculated as the weighted average eligible Low Density Discount of
15 irrigation customers weighted with eligible irrigation loads. See Documentation Table 3.14.

16
17 Forecast revenue for irrigation loads will be calculated using an IRD TOCA derived by dividing
18 the sum of the irrigation loads (expressed in aMW) by the sum of all RHWMs. This IRD TOCA
19 will be applied consistent with Section 5 of the TRM for calculation of forecast irrigation
20 revenues from the Composite Customer Charge, the Non-Slice Customer Charge, and the Load
21 Shaping Charge. This discount will be seasonally available to qualifying loads during May,
22 June, July, August, and September. See TRM, BP-12-A-03 at 93. The calculation is shown on
23 Table 2.3.3 of Documentation.

24
25 **3.1.11.2 Irrigation Rate Discount Bill Credit**

26 The irrigation credit available to a customer with eligible irrigation load is equal to the monthly
27 irrigation load set forth in Exhibit D of the customer's CHWM contract multiplied by the IRD

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

4 **3.1.11.3 Irrigation Rate Discount True-Up**

6 At the end of each irrigation season, customers with eligible irrigation load will send to BPA
7 their measured May through September irrigation load amounts. If BPA determines that the
8 measured irrigation load amounts are less than the eligible irrigation load amounts set forth in
9 Exhibit D of the customer's CHWM contract, then the purchaser shall reimburse to BPA excess
10 IRD credits. Excess IRD credits will be calculated as the IRD rate multiplied by the difference
11 between the contract irrigation load and the measured irrigation load. See GRSP II H.2.

13 **3.1.12 PFp Melded Rates (Non-Tiered Rate)**

14 Melded PF Public rates are included in the PF rate schedule. The PFp Melded rates consist of
15 12 HLH and 12 LLH Energy rates and 12 Demand rates. The PFp Melded Energy rates are
16 equal to the Load Shaping rates less a single \$/MWh value. The single \$/MWh value adjusts the
17 Load Shaping Rates so that the PFp Melded Energy rates, in conjunction with the demand
18 revenue, do not collect more or less revenues than the Tier 1 and Tier 2 revenue requirement
19 allocated to the PFp loads. This \$/MWh value is the PFp Melded Equivalent Energy Scalar,
20 which is also used in the Slice True-Up to determine the actual DSI revenue credit. This
21 calculation is shown in Documentation Table 2.5.7.2. The applicable Demand rates are equal to
22 the PFp Tier 1 Demand rates.

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

1 **3.1.13 PFp Resource Support Services**

2 BPA offered customers access to RSS and related services for their variable, non-dispatchable
3 non-Federal resources, in accordance with the CHWM contract. The related services include
4 Transmission Scheduling Service and Transmission Curtailment Management Service. In
5 general, these services are designed to financially convert a variable, non-dispatchable resource
6 into a flat annual block of power or the specified monthly/diurnal resource shape found in
7 Exhibit A of the customer’s CHWM contract.

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

16
17 Costs for RSS are not allocated to the Tier 2 cost pools in this rate period because there are no
18 variable, non-dispatchable resources assigned to the Tier 2 cost pools. Costs for TSS are
19 allocated to the Tier 2 cost pools, and the method for doing so is described above in
20 section 3.1.7.2. Costs for TCMS events associated with Tier 2 rate service are recovered through
21 a mechanism known as the Tier 2 Rate TCMS Adjustment, described above in section 3.1.9.1.

22
23 **3.1.13.1 RSS Rates**

24 RSS rates are included in both the PF rate schedule and the FPS rate schedule. The rates
25 described here under the PFp section include Diurnal Flattening Service energy and capacity
26 rates, Resource Shaping rates and adjustment, Secondary Crediting Service shortfall and
27 secondary energy rates, and Secondary Crediting Service Administrative Fee rate. The rates

1 described under the FPS section below include Forced Outage Reserve Service energy and
2 capacity rates, TSS rate, and TCMS rate. In total, about \$3 million of forecast RSS and TSS-
3 related revenue credits are applied annually to the Tier 1 cost pools. See Documentation Tables
4 3.1 and 3.2.

6 **3.1.13.2 RSS Diurnal Flattening Service, Resource Shaping Charge, and Resource Shaping** 7 **Charge Adjustment**

8 **3.1.13.2.1 Diurnal Flattening Service (DFS)**

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

15
16 The RSS module of RAM calculates a unique set of rates and charges for each resource to which
17 DFS is applied. Illustrative model runs for example resources are included in the Documentation
18 to show how the various charges and rates would be calculated for a sample resource. See
19 Documentation, Tables 3.15–3.22. Also included in the Documentation are the final rates and
20 charges calculated for the customers that have requested DFS for their resources. See
21 Documentation Table 3.23. The PF-12 rate schedule includes a section on the general rate
22 application of the DFS-related charges. See PF-12 Rate Schedule, section 5.1. The GRSPs
23 include the calculations for the DFS capacity charges, DFS energy charges, and Resource
24 Shaping charges for the resources to which DFS is applied. See GRSP II.P.

1 Briefly, DFS charges include the following elements:

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

11
12 When DFS is applied to a resource, other charges must be added to the DFS charges to complete
13 the financial conversion to a flat annual block of power. These include the following elements:

- 14 • The Resource Shaping charge, based on the Resource Shaping rates (which are equal
15 to the PFp Tier 1 Load Shaping rates) to financially convert the resource amounts that
16 have been flattened on a monthly/diurnal basis into a flat annual block of power.
- 17 • A Resource Shaping Charge Adjustment, based on the Resource Shaping rates, to
18 correct for generation forecast error.

19 20 **3.1.13.2.2 DFS Capacity Charge**

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

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

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

6
7 **Monthly Firm Capacity.** The RSS module of RAM calculates monthly firm capacity amounts
8 for each resource. This calculation represents the lowest level of historical generation in a HLH
9 period for each month, after accounting for planned and forced outages. Because planned
10 outages are not included in the FY 2009 data, a planned outage adjustment is not necessary.
11 Therefore, the firm capacity of a resource is calculated as the percentile equal to the forced
12 outage rating calculated from the historical monthly HLH generation levels. In other words, a
13 resource with a 5 percent forced outage rating would have a firm capacity amount equal to the
14 5th percentile of the hourly historical generation amounts for the HLH period of a month.

15
16 The billing determinant also includes a planned outage adjustment. If the historical hourly data
17 reflects an outage that was planned, the model does a second calculation of the monthly firm
18 capacity amount. This test runs the same calculation above, but calculates the value
19 approximately equal to the forced outage percentile of an hourly sample that does not include the
20 hours that were identified as a planned outage. If the number of planned outage hours is less
21 than 25 percent of the HLH in the month, no further adjustments are made to the value calculated
22 by the planned outage calculation of firm capacity. If the number of planned outage hours is
23 equal to 25 percent of the HLH in the month but less than 75 percent of the hours in the month,
24 the planned outage adjusted firm capacity value is reduced by multiplying it by one minus the
25 percentage of planned hours in the month. If the number of planned outage hours in the month is
26 equal to or greater than 75 percent of the HLH in the month, the firm capacity of the resource in
27 that particular month is set to zero.

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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.

1 **DFS Energy Billing Determinant.** The DFS energy billing determinant is the total actual
2 generation for the particular resource during the billing month. The actual generation amounts
3 will be either the resource meter readings or resource transmission schedules if the resource
4 requires an e-Tag. For wind resources within the BPA Balancing Authority Area, transmission
5 curtailments associated with Dispatcher Standing Order (DSO) 216 will be treated as lowered
6 scheduled amounts when calculating the actual generation for such a resource.

7
8 **DFS Energy Charge.** The DFS energy charge is the product of multiplying the DFS energy rate
9 by the DFS energy billing determinant for each month. Table 3.23 of the Documentation shows
10 the DFS energy rates that are calculated for the individual resources to which DFS is applied.
11 GRSP II.P.1.(b) includes the formula for calculating the DFS energy charges for the individual
12 resources to which DFS is applied.

13 14 **3.1.13.2.4 Resource Shaping Charge**

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

20
21 **Resource Shaping Billing Determinant.** The Resource Shaping billing determinant for each
22 resource is the difference between the planned monthly/diurnal generation from the Exhibit D
23 amounts and the annual average generation from the Exhibit A amounts for the same year.

1 **Resource Shaping Charge.** For each resource, the Resource Shaping charge is the product of
2 multiplying the Resource Shaping rate by the Resource Shaping billing determinant. The sum of
3 the values is divided by 24 (or 12 if the service applies only in FY 2013) to calculate a flat
4 monthly charge. On a monthly basis this calculation can result in a charge or a credit.
5 The flat monthly Resource Shaping charge that results from this calculation will be reflected on
6 the customer's monthly bill. Example calculations for a solar resource and a wind resource are
7 included in Documentation Tables 3.18 and 3.22. Table 3.23 of the Documentation shows the
8 Resource Shaping charges that are calculated for the individual resources to which DFS is
9 applied. GRSP II.P.1.(c) includes the formula for calculating the Resource Shaping charges for
10 the individual resources to which DFS is applied.

11
12 For Small, Non-Dispatchable Resources (as defined in the CHWM contract), the Resource
13 Shaping charge will not apply. The actual generation amounts will be used in the calculation of
14 the Actual Monthly/Diurnal Tier 1 Load when calculating the PFp Tier 1 Load Shaping charge
15 and Demand charge billing determinants.

16 17 **3.1.13.2.5 Resource Shaping Charge Adjustment**

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

20
21 **Resource Shaping Charge Adjustment Billing Determinant.** For each resource, the billing
22 determinant is the difference between the planned monthly/diurnal generation from CHWM
23 contract Exhibit D amounts and the actual monthly/diurnal generation of the resource. The
24 actual generation amounts will be either the resource meter readings or resource transmission
25 schedules if the resource requires an e-Tag. The calculation of the Resource Shaping Charge
26 Adjustment billing determinant will also include energy provided through Forced Outage

1 Reserve Service (FORS), TCMS, planned outage replacement, economic dispatch, and
2 Unauthorized Increases in the determination of actual generation. For wind resources within the
3 BPA Balancing Authority Area, transmission curtailments associated with DSO 216 will be
4 treated as lowered scheduled amounts when calculating the actual generation for such a resource.

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

14 15 **3.1.13.2.6 DFS and Resource Shaping Charge Application to Tier 1 Augmentation**

16 The TRM states that RSS pricing will be used to make certain Federal resource acquisitions
17 financially equivalent to a flat block. TRM, section 8. In addition, Tier 1 Augmentation is
18 assumed to be in the shape of an annual flat block purchase for ratemaking purposes. TRM,
19 section 3.5. The costs of Klondike III, a wind resource, are allocated to Tier 1 Augmentation.
20 The RSS module of RAM calculates a DFS Capacity charge, DFS Energy charge, and Resource
21 Shaping charge for Klondike III. The billing determinant for the DFS Energy charge is the
22 planned generation amount based on the historical generation year data, in lieu of actual
23 generation data. In addition, the RSS module calculates a TSS charge for Klondike III. The sum
24 of the charges for Klondike III for each year is allocated to the Tier 1 Composite cost pool under
25 the “Augmentation RSS and RSC Adder” line item. There is no Resource Shaping Charge

1 Adjustment applied to Klondike III. Documentation Table 3.23 shows the summary DFS,
2 Resource Shaping, and TSS charges that are calculated for Klondike III.

3 4 **3.1.13.3 RSS Secondary Crediting Service (SCS)**

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

10
11 Credits are provided to the customer when its resource generates more than the contract amount.
12 This additional generation would increase BPA's revenues because of the increased secondary
13 energy BPA can market or would lower BPA's costs because of reduced balancing purchases.
14 Likewise, when generation is less than the contract amounts, the customer is charged, because
15 BPA's secondary revenues would be lower or BPA's balancing costs would be higher. The
16 unanticipated credit or cost BPA would experience is passed through to the customer by the SCS,
17 using the posted Resource Shaping rate as the market rate. The PF-12 rate schedule includes a
18 section on the rate application of the SCS-related charges. The GRSPs include the formulas for
19 calculating the SCS charges for the resources to which SCS is applied. GRSP II.P.2.
20 Documentation Table 3.23 includes the individual SCS Administrative Charges for the
21 individual non-Federal resources to which SCS is applied.

22 23 **3.1.13.3.1 SCS Pricing Summary**

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

1 The SCS charges include the following elements:

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

8 **3.1.13.3.2 SCS Shortfall Energy Charges and Secondary Energy Credits**

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

11
12 **SCS Billing Determinant.** For each resource, the billing determinant is the difference between
13 the actual monthly/diurnal generation and the monthly/diurnal generation from Exhibit A
14 amounts. The actual generation amounts will be either the resource meter readings or resource
15 transmission schedules if the resource requires an e-Tag. For SCS, Option 1 only (the power
16 exchange between the customer and BPA), the actual generation amounts shall be net of
17 transmission losses on the BPA transmission system. See GRSP III.A.13. The actual generation
18 shall include energy amounts provided through TCMS.

19
20 **SCS Shortfall Energy Charge/Secondary Energy Credit.** For each resource, the charge or
21 credit is the product of multiplying the SCS Energy rate by the SCS Energy billing determinant
22 for each monthly/diurnal period. If the actual generation exceeds the Exhibit A amount, the
23 customer will receive a credit. If the actual generation is less than the Exhibit A amount, the
24 customer will receive a charge. GRSP II.P.2.(a) includes the formula for calculating the SCS
25 Shortfall Energy Charges/Secondary Energy Credits for the individual resources to which SCS is
26 applied.

1 **3.1.13.3.3 SCS Administrative Charge**

2 A customer's SCS Administrative Charge will be calculated in the form of a capacity reservation
3 fee. This capacity reservation fee's structure mirrors the structure of the FORS capacity charge,
4 described below in section 3.5.1.

5
6 **SCS Administrative Rate.** The rates used to calculate the SCS Administrative Charge are the
7 monthly PFp Tier 1 Demand rates.

8
9 **SCS Administrative Charge Billing Determinant.** For each resource, the billing determinant
10 is the monthly HLH Exhibit A amount multiplied by the forced outage rating.

11
12 **SCS Administrative Charge.** For each resource, the SCS Administrative charge is the product
13 of multiplying the SCS Administrative rate by the SCS Administrative billing determinant for
14 each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The flat
15 monthly SCS Administrative charge that results will be specified in section 2.5.3.2 of Exhibit D
16 of the CHWM contract. Documentation Table 3.23 shows the SCS Administrative charges that
17 are calculated for the individual resources to which SCS is applied. GRSP II.P.2.(b) includes the
18 formula for calculating the SCS Administrative Charge for the individual resources to which
19 SCS is applied.

20
21 **3.1.13.4 Additional PFp RSS Considerations**

22 **3.1.13.4.1 Forced Outage Rating**

23 All generally recognized types of generating resources have a standard forced outage rating.
24 This rating represents the average percentage of time that a generating resource is unavailable for
25 load service due to unanticipated breakdown. BPA uses a minimum five percent forced outage
26 rating for hydroelectric resources, seven percent for thermal resources, and ten percent for all
27 other resources. Customers taking services that have charges including the use of a forced

1 outage rating may request that BPA increase the forced outage rating for their resource, and
2 those with a resource other than a hydroelectric resource may request that BPA decrease the
3 forced outage rating to as low as seven percent.
4

5 **3.1.13.4.2 Historical Generation Year Resource Amounts Adjusted for Schedules**

6 Typically, the RSS module of RAM will use scheduled amounts for resources that require an
7 e-Tag and meter amounts for “behind-the-meter resources.” However, for small resources or
8 small shares of a resource, BPA may apply a meter amount instead of a schedule amount for
9 purposes of pricing RSS if the meter amounts produce lower RSS rates and charges. This
10 adjustment applies to both RSS provided under the PF rate schedule, discussed above, and the
11 FPS rate schedule, described below.
12

13 **3.1.13.4.3 Credits to the PFp Tier 1 Customer Cost Pools**

14 Forecast revenue credits will be calculated from the RSS charges. All revenues except those
15 from the Resource Shaping Charge will be credited to the appropriate PFp Tier 1 Customer Rate
16 cost pools. The forecast revenue from the Resource Shaping Charge sales is a revenue credit to
17 the Non-Slice cost pool. Additional information on these revenue credits is found in
18 sections 3.1.2.1 and 3.1.2.2.
19

20 **3.2 Priority Firm Exchange Rate Design**

21 The PF Exchange rate applies to participants in the Residential Exchange Program for sales of
22 exchange energy pursuant to a Residential Sale and Purchase Agreement (RPSA) or a REP
23 Settlement Implementation Agreement (REPSIA). Under either an RPSA or REPSIA, the PF
24 Exchange rate is applied to BPA’s sales of exchange energy, and the participating utility’s ASC
25 is applied to BPA’s purchase of exchange energy, where the exchange energy is equal to the
26 utility’s eligible residential and small farm load. The difference between the amount BPA pays

1 for exchange “purchases” and the amount BPA receives for exchange “sales” determines the
2 amount of monetary REP benefits BPA pays the utility. The PF Exchange rate also applies to
3 any actual power sales to exchanging utilities under contractual “in-lieu” provisions.
4

5 The PF Exchange rate is comprised of two components: two common Base PF Exchange rates
6 (one for COUs with CHWM contracts and another for all other participants), and utility-specific
7 REP Surcharges. Neither component of the PF Exchange rate is diurnally differentiated or
8 contains an additional charge for demand. Each participant’s ASC is a single mills/kWh rate
9 applied to all kilowatthours. Likewise, the rate design for each participant’s PF Exchange rate is
10 a single mills/kWh rate applied to all kilowatthours.
11

12 The two Base PFX rates are computed within RAM based on the average PF rate immediately
13 prior to the determination of section 7(b)(2) rate protection. At this point in the ratemaking
14 process, no 7(b)(2) rate protection has been determined and, therefore, the Base PFX rates bear
15 no rate protection costs. The PFX rate applicable to IOUs (and any eligible COU without a
16 CHWM contract) is computed by dividing all costs allocated to the PF rate pool divided by all
17 PF rate pool loads and then adding a transmission charge for delivering the exchange power to
18 the customer. The PFX rate applicable to COUs with CHWM contracts is calculated in the same
19 manner, except that the costs allocated to Tier 2 cost pools are excluded from the numerator, and
20 loads served at Tier 2 rates are excluded from the denominator.
21

22 Under the 2012 REP Settlement, the utility-specific 7(b)(3) surcharge to recover the cost of
23 providing 7(b)(2) rate protection continues to be assessed, but the surcharge for IOUs also
24 includes the allocation of the costs of Refund Amounts. See section 2.2.1.3. The amount of
25 7(b)(2) rate protection costs allocated to the PFX rates is allocated to each REP participant on a
26 pro rata basis using REP benefits calculated using the Base PFX rates (Unconstrained Benefits)
27 as the allocator. The cost of Refund Amounts is allocated to each IOU using IOU Unconstrained

1 Benefits as the allocator. The total amount allocated to each REP participant is divided by the
2 participant's exchange load to derive its utility-specific 7(b)(3) surcharge.

3
4 For each REP participant, the applicable Base PFX rate is added to its utility-specific 73
5 surcharge to determine its utility-specific PFX rate. For each month of the rate period, the
6 participant will submit to BPA its exchange load for the prior month. BPA will multiply this
7 invoiced exchange load by the difference between the participant's ASC and its PFX rate to
8 calculate the amount of REP benefits payable to the participant.

9 10 **3.3 Industrial Firm Power (IP) Rate Design**

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

13 14 **3.3.1 IP Energy Rates**

15 The IP rate design includes 24 monthly/diurnal Energy rates, two for each month, one each for
16 HLH and LLH. Monthly and diurnal differentiation of IP energy rates is performed based on the
17 HLH and LLH differentiation of the PFp Melded rate (see section 3.1.12).

18
19 IP energy rates are determined by adjusting the PFp Melded rates by the Value of Reserves
20 (VOR) provided by the DSI load, the net industrial margin, and the REP. See Documentation
21 Table 2.5.7.3.

22 23 **3.3.1.1 IP Adjustment for Value of Reserves Provided**

24 A VOR credit is included in the IP rate, as provided in section 7(c)(3) of the Northwest Power
25 Act. See section 1.2.2. The FY 2012-2013 rate period DSI power sales forecast is 340.5aMW.

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

3
4 The first step for valuing interruption reserves provided by DSIs is to determine a marginal price
5 for these reserves. Because the DSI-supplied reserves are used to meet BPA's reserve
6 obligations, the cost of Operating Reserves – Supplemental is used to establish the marginal
7 value. The Operating Reserves documented in the Generation Inputs Study are provided by the
8 FCRPS and are available for any hour and on any day.

9
10 The second step in valuing the DSI reserves is to determine the quantity of reserves provided.
11 To calculate this quantity, the load of aluminum DSIs available for interruption is reduced to
12 account for wheel-turning load that cannot be curtailed. The wheel-turning load for aluminum
13 DSIs is forecast to be 6 aMW. No wheel-turning amount is established for Port Townsend. The
14 interruption reserves provided are 10 percent of the remaining DSI load. The VOR credit
15 included in the IP-12 rate is 0.94 mills/kWh. See Documentation Table 2.4.1 for calculation of
16 the value of DSI reserves.

17 18 **3.3.1.2 IP Rate Typical Margin**

19 Another component of the IP rate is the typical margin, as provided in section 7(c)(2) of the
20 Northwest Power Act. See section 1.2.2. The typical margin is based generally on the overhead
21 costs that COUs add to the cost of power in setting their retail industrial rates. The typical
22 margin included in the IP-12 rate is 0.685 mills/kWh. The methods and calculations used to
23 determine the typical margin are discussed in Appendix A.

1 **3.3.1.3 REP Surcharge**

2 The final component of the IP rate is the REP Surcharge. Section 7(b)(3) of the Northwest
3 Power Act provides that the cost of 7(b)(2) rate protection afforded to preference customers be
4 allocated to all other power sold, which includes power sold at the IP rate. See section 1.2.2.
5 The cost of rate protection allocated to the IP rate is determined pursuant to the 2012 REP
6 Settlement and is included in the IP-12 rate. The IP-12 REP Surcharge is 7.72 mills/kWh. See
7 Documentation Table 2.4.14 for calculation of the REP Surcharge.

8
9 **3.3.2 IP Demand Rates**

10 The Demand rates for the IP rate schedule are equal to the PFp Demand rates, as described in
11 section 3.1.6.3.

12
13 As with the PFp Demand charge, the IP Demand billing determinant is applied to only a portion
14 of the DSI peak demand placed on BPA. The IP Demand billing determinant in each billing
15 month will be equal to the DSI's highest HLH schedule, or metered amount, minus the average
16 HLH schedule amount, or metered amount, less any applicable Industrial Demand Adjuster.

17
18 The Industrial Demand Adjuster is a monthly quantity of demand (expressed in kW) that is
19 subtracted from the hourly peak schedule amount when calculating the IP Demand billing
20 determinant. Power Rate Schedules, BP-12-A-02B, *e.g.*, section 2.2.2

21
22 **3.4 New Resources (NR) Rate Design**

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

1 **3.4.1 NR Energy Rates**

2 Monthly and diurnal differentiation of NR energy rates is calculated based on the HLH and LLH
3 differentiation of the PFp Load Shaping rates. See Documentation Table 2.5.7.4.

4
5 The NR energy rates are determined by adjusting the PFp Load Shaping rates by an equal scalar
6 until the NR energy rates recover the allocated NR revenue requirement minus the forecast
7 Demand charge revenue. See Documentation Table 2.5.7.4.

8
9 After the scaling process is complete, an REP Surcharge is added to each of the monthly/diurnal
10 energy rates. Section 7(b)(3) of the Northwest Power Act provides that the cost of 7(b)(2) rate
11 protection afforded to preference customers be allocated to all other power sold, which includes
12 power sold at the NR rate. See section 1.2.2. The cost of rate protection allocated to the NR rate
13 is determined pursuant to the 2012 REP Settlement. The NR-12 REP Surcharge is
14 7.72 mills/kWh. See Documentation Table 2.4.14 for calculation of the REP Surcharge.

15
16 **3.4.2 NR Demand Rates**

17 The Demand rates for the NR rate schedule are equal to the PFp Demand rates, as described in
18 section 3.1.6.3.

19
20 As with the PFp Demand charge, the NR Demand billing determinant is only a portion of the
21 peak demand placed on BPA. The NR Demand billing determinant will be equal to the highest
22 NR Hourly Load during HLH less the average hourly HLH energy purchased in that particular
23 month at the NR energy rates.

1 **3.5 Firm Power Products and Services Rate Design, Resource Support Services,**
2 **and Transmission Scheduling Service**

3 Products and services available under this rate schedule are described in BPA’s 2012 Power Rate
4 Schedules, BP-12-A-02B. Sales under this rate schedule are discretionary: BPA is not obligated
5 to sell any of these products, even if such sales will not displace PF, NR, or IP sales. Products
6 priced under the FPS-12 rate schedule may be sold at market-based or negotiated rates, which
7 may have a demand component, an energy component, or both. Applicable transmission rates
8 will apply to the extent required to purchases of firm power under the FPS-12 rate.

9
10 The FPS rate schedule provides for seven products and services: (1) Firm Power and Capacity
11 Without Energy; (2) Supplemental Control Area Services; (3) Shaping Services; (4) Reservations
12 and Rights to Change Services; (5) Reassignment or Remarketing of Surplus Transmission
13 Capacity; (6) Services for Non-Federal Resources; and (7) Unanticipated Load Service.

14
15 **3.5.1 Firm Power and Capacity Without Energy**

16 When available, BPA sells firm power, including secondary energy, or firm capacity for use
17 within the Pacific Northwest and outside of the Pacific Northwest. Such power sales are made
18 under the FPS rate schedule at rates and billing determinants specified by BPA or as mutually
19 agreed by BPA and the customer. Sales of firm power may be subject to an REP Surcharge.

20 The applicability of an REP Surcharge will be made by BPA at the time of the sale, as set forth
21 in the 2010 REP Settlement Agreement.

22
23 **3.5.2 Supplemental Control Area Services**

24 BPA sells supplemental control area services, when available, for use within the Pacific
25 Northwest and outside of the Pacific Northwest. Such services are sold under the FPS rate
26 schedule at rates and billing determinants specified by BPA or as mutually agreed by BPA and
27 the customer.

1 **3.5.3 Shaping Services**

2 BPA sells shaping services, when available, for use within the Pacific Northwest and outside of
3 the Pacific Northwest. Such services are sold under the FPS rate schedule at rates and billing
4 determinants specified by BPA or as mutually agreed by BPA and the customer.
5

6 **3.5.4 Reservations and Rights to Change Services**

7 BPA offers reservations of power and services, when available, and the rights to change sales
8 and services for use within the Pacific Northwest and outside of the Pacific Northwest. Such
9 services are sold under the FPS rate schedule at rates and billing determinants specified by BPA
10 or as mutually agreed by BPA and the customer.
11

12 **3.5.5 Reassignment or Remarketing of Surplus Transmission Capacity**

13 BPA reassigns or remarkets its surplus transmission capacity, when available, that has been
14 purchased from a transmission provider, including Transmission Services, consistent with the
15 terms of the transmission provider’s Open Access Transmission Tariff. BPA sells this surplus
16 transmission capacity to parties within the Pacific Northwest and outside of the Pacific
17 Northwest. Such services are sold under the FPS rate schedule at rates and billing determinants
18 specified by BPA or as mutually agreed by BPA and the customer.
19

20 **3.5.6 Services for Non-Federal Resources**

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

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

5
6 The FPS rate schedule includes a section on the general rate application of the FORS- and TSS-
7 related charges. The GRSPs include the formulas for calculating the FORS Capacity and Energy
8 Charges and TSS and TCMS Charges for the resources to which FORS or TSS/TMCS is applied.

9 10 **3.5.6.1 Forced Outage Reserve Service**

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

19 20 **3.5.6.1.1 FORS Pricing Summary**

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

24
25 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).

1 **3.5.6.1.3 FORS Energy Charge**

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

4
5 **FORS Energy Rate.** The rate for the energy provided during the first 24 hours of a forced
6 outage will be the average of the hourly Powerdex Mid-C Price or its replacement during the
7 hours of the forced outage. The rate for energy provided after the first 24 hours of a forced
8 outage will be the diurnal Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index
9 or its replacement for the applicable diurnal period the energy is provided. If any of the Mid-C
10 prices specified above is less than zero, the FORS Energy rate calculation will be zero for such
11 negative value.

12
13 **FORS Energy Billing Determinant.** The FORS Energy billing determinant is the total actual
14 replacement energy a resource requires to meet the planned generation amount specified in
15 Exhibit D of the customer’s CHWM contract, subject to the FORS energy limits specified
16 therein.

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

21
22 **3.5.6.2 Transmission Scheduling Service and Transmission Curtailment Management**
23 **Service**

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

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

13 **3.5.6.2.1 TSS/TCMS Pricing Summary**

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

23
24 The TSS/TCMS charges include the following elements:

- 25 • A monthly TSS charge based on the dedicated resource megawatthour amounts found
26 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

1 transaction-based. It is the result of multiplying 30 (the average number of schedules in a month,
2 *i.e.*, one per day) by the forecast operations scheduling cost for the rate period, divided by the
3 total number of schedules Power Services produced in FY 2009 and FY 2010.

4
5 Examples for a wind resource and a biomass resource show how the TSS charge described above
6 is calculated. See Documentation Tables 3.20 and 3.22. Table 3.23 of the Documentation shows
7 the individual TSS charges that are calculated for the individual resources to which only TSS is
8 applied and individual resources to which TSS is applied in addition to other RSS products.
9 GRSP II.P.4.(a)(3) shows the formula for calculating the TSS charge for the individual resources
10 to which TSS is applied.

11 12 **3.5.6.2.3 TCMS Charge**

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

17
18 **TCMS Charge if Replacement Power is Provided.** The TCMS rate will be the Powerdex
19 Mid-C hourly index price or its replacement for each hour the transmission event occurs. If a
20 Mid-C price is less than zero, the TCMS Energy rate for that hour will be zero. The TCMS
21 billing determinant is the total actual kilowatthours in each hour of replacement power BPA
22 supplies. For each eligible resource, the TCMS charge is the product of multiplying the TCMS
23 rate by the TCMS billing determinant for each hour of the month.

24
25 **TCMS Charge if Alternative Transmission is Provided.** If Point-to-Point transmission is used
26 for the alternate transmission path used to deliver the customer's eligible resource, for each

1 resource the TCMS charge is the cost of the additional Point-to-Point transmission purchases
2 plus any additional costs, including real power losses, associated with using the replacement
3 transmission.

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

7
8 For the BP-12 rate period, the TCMS charge does not include a non-firm Network or Point-to-
9 Point Reservation Fee. BPA is reserving the right to include such a fee in future rate periods for
10 customers wheeling their non-Federal resource to their loads on non-firm Network or non-firm
11 Point-to-Point transmission.

12
13 Application of TCMS to the Tier 2 rates is described in section 3.1.9.1.

14 15 **3.5.6.3 TSS Charge Application to Tier 1 Augmentation**

16 The TRM states that RSS pricing will be used to make Federal resource acquisitions financially
17 equivalent to a flat block. TRM section 8. In addition, Tier 1 Augmentation is assumed for
18 ratemaking purposes to be in the shape of an annual flat block purchase. TRM section 3.5. The
19 one resource whose costs are allocated to Tier 1 Augmentation is Klondike III, a scheduled
20 resource that requires an e-Tag. The RAM RSS module calculates a TSS Charge for this
21 resource. This TSS Charge is added to the RSS charges for each year of the rate period that are
22 allocated to the Composite cost pool under the “Non-Slice Augmentation RSC Revenue
23 Debit/(Credit)” line item.

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

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

7
8 **3.5.7 Unanticipated Load Service (ULS)**

9 Under the FPS-12 rate schedule, the Resource Replacement (RR) rate will be applied to
10 Unanticipated Load Service for delays in the on-line date of a Customer’s specified resource for
11 Above-RHWM service, New Specified Resources that are 10 aMW or less and either experience
12 permanent failure during the rate period or fail to come online, and Transfer customers that both
13 (1) cannot secure Firm Network Transmission (NT) from source to sink for their Dedicated Non-
14 Federal Resource to their Above-RHWM Load by the time power deliveries are to begin under
15 the Regional Dialogue contract and (2) are expected to face high TCMS charges due to their
16 reliance on Secondary Network Transmission, while they pursue Firm Network Transmission.

17
18 The energy rate for the RR rate is equal to the Load Shaping rate or the projected market price
19 calculated when a request for ULS is made, whichever is greater. See section 3.1.6.2 for a
20 description of the Load Shaping rate. The ULS Demand rate is equal to the PFp Demand rate,
21 described in section 3.1.6.3. The ULS under the FPS-12 rate schedule is specified in GRSP
22 II.U.4.

23
24 **3.6 General Transfer Agreement Service Rate Design**

25 Transfer Services are the transmission and distribution services BPA acquires from other
26 transmission providers to transmit Federal power to BPA customers located within third-party-
27 owned transmission systems. Transfer Service customers may be subject to one or two separate

1 charges from BPA under the General Transfer Agreement Service (GTA-12) rate: (1) the
2 General Transfer Agreement (GTA) Delivery Charge, and (2) the Transfer Service Operating
3 Reserve Charge. In addition to these charges, Transfer Service customers are responsible for the
4 cost of any distribution upgrades associated with their respective points of delivery, as provided
5 in the Supplemental Direct Assignment Guidelines (GRSP I.E.).
6

7 **3.6.1 GTA Delivery Charge**

8 The GTA Delivery Charge, section I of the GTA-12 rate schedule, is a rate for low-voltage
9 delivery service of Federal power provided under GTAs and other non-Federal transmission
10 service agreements over a third-party transmission system. The GTA Delivery Charge applies to
11 power customers that take delivery at voltages below 34.5 kV when BPA is paying for the
12 transfer service over the third-party transmission system, unless such costs have been directly
13 assigned to the specific customer.
14

15 Since 2002, the GTA Delivery Charge has mirrored the Transmission Services Utility Delivery
16 Charge. For the FY 2010-2011 rate period, the Transmission Services Utility Delivery rate was
17 set at \$1.119 per kilowatt per month; GTA-10 was consistent with that rate. Power Services is
18 continuing the application of the \$1.119 per kilowatt per month rate and billing factor for the
19 GTA-12 Delivery Charge.
20

21 The GTA Delivery Charge revenue forecast is approximately \$2.5 million per year, as shown in
22 Table 4.11 of Documentation. This revenue forecast was derived by applying the GTA Delivery
23 Charge of \$1.119 per kilowatt per month to the forecast peak loads at the points of delivery at
24 which customers currently pay the GTA Delivery Charge.
25
26

1 **3.6.2 Transfer Service Operating Reserve Charge**

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

11
12 In anticipation of this potential change, the Transfer Service Operating Reserve Charge for the
13 FY 2012-2013 rate period is designed to mitigate the cost shift described above in the event the
14 Commission adopts WECC’s proposed change. The Transfer Service Operating Reserve Charge
15 rate, if assessed, would be the same as the ACS-12 rate for Operating Reserves that Transmission
16 Services charges to customers that have load in the BPA balancing authority area.

17
18 Due to the uncertain nature of if and when WECC’s proposed changes may be adopted by the
19 Commission and implemented by the various transmission providers, the implementation of the
20 Transfer Service Operating Reserve Charge has been conditioned upon the satisfaction of three
21 criteria: (1) BPA serves the power customer by Transfer Service; (2) the Transfer Service
22 customer does not pay Transmission Services for Operating Reserves based on 3 percent of the
23 customer’s load; and (3) BPA is assessed Operating Reserve charges from a third-party
24 transmission provider to transfer Federal power to the power customer’s load. Power Services
25 intends to assess the Transfer Service Operating Reserve Charge only if all three criteria have
26 been satisfied.

1 The forecast revenue associated with the Transfer Service Operating Reserve Charge is zero,
2 because implementation of the Transfer Service Operating Reserve Charge will generally result
3 in no net revenue impact. It is anticipated that the increased revenue from Transfer Service
4 customers will be offset by the increased ancillary service costs Power Services will pay to third-
5 party transmission systems.

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1 **4. REVENUE FORECAST**

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

14
15 In addition to forecasts of revenues, this study calculates power purchase expenses that are
16 directly related to generation levels of surplus energy. Power purchases are included in the
17 forecast for FY 2011-2013 and discussed in section 4.5.

18
19 Also included in the revenue forecast are revenue calculations for the current year, FY 2011.
20 This forecast is needed to estimate the amount of financial reserves available to BPA at the
21 beginning of the rate period. See Power Revenue Requirement Study, section 1.1.

22
23 The revenue forecast is divided into four main categories: (1) gross sales, described in
24 section 4.1; (2) miscellaneous revenues, described in section 4.2; (3) generation inputs for
25 ancillary, control area, and other services, described in section 4.3; and (4) Treasury credits,
26 described in section 4.4. The change in organization from the WP-10 revenue forecast is

1 designed to increase consistency with other BPA financial documents in terms of revenue
2 categories. In addition, there are multiple new revenue categories compared to the WP-10
3 revenue forecast.

4 **4.1 Revenue Forecast for Gross Sales**

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

14 **4.1.1 Firm Power Sales under Subscription and CHWM Contracts**

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

22 For FY 2012-2013, revenues from PF power sales pursuant to CHWM contracts are computed
23 using the product of (1) forecast loads assuming normal weather, documented in the Power
24 Loads and Resources Study and accompanying Documentation; and (2) the appropriate PF rates
25 derived by RAM2012. Revenue forecasting inputs and results are managed and calculated
26 pursuant to the CHWM contracts using a database referred to as the Revenue Forecasting

1 Application (RFA). Revenues are reported for Tier 1 Composite (Slice and Non-Slice), Load
2 Shaping, and Demand (including the Low Density Discount and Irrigation Rate Discount
3 credits), and any additional Tier 2 or RSS charges.
4

5 **4.1.1.1 Composite and Non-Slice Customer Charges**

6 Revenues from each customer for the Composite and Non-Slice Customer charges are based on
7 the customer's TOCA and the customer's contractually specified products. Revenues obtained
8 from the Composite and Non-Slice Customer charges represent the majority of revenues from
9 firm power sales under CHWM contracts. Composite and Non-Slice revenues for FY 2012-2013
10 are listed in Table 3, lines 4 – 5, and Documentation Table 4.2, lines 10 – 11.
11

12 **4.1.1.2 Load Shaping Charge**

13 The Load Shaping charge is designed to reflect the costs and benefits of shaping the Tier 1
14 System Capability to the monthly/diurnal shape of a customer's Below-HWM load. A charge to
15 the customer results when the customer's shaped load is greater than its share of the Tier 1
16 System Output; the customer will receive a credit from BPA when the opposite occurs. The
17 Load Shaping charge is described in detail in section 3.1.6.2, and an example calculation of the
18 Load Shaping charge is available in Documentation Table 4.6. Load Shaping revenues for
19 FY 2012-2013 are listed in Table 3, line 7, and Documentation Table 4.2, line 13.
20

21 **4.1.1.3 Demand Charge**

22 The Demand charge is applicable to customers purchasing Load Following or Block with
23 Shaping Capacity products. The Demand charge is calculated using customer-specific
24 information including actual Customer Tier 1 System peak, average actual monthly Below-
25 HWM load occurring in HLH, CDQ, and Super Peak Credit (if applicable). Calculation of a
26 customer's Demand charge is described in section 3.1.6.3, and an example calculation is

1 available in Documentation Table 4.6. Demand revenues for FY 2012-2013 are listed in Table 3,
2 line 8, and in Documentation Table 4.2, line 14.

3 4 **4.1.1.4 Irrigation Rate Discount**

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

14 15 **4.1.1.5 Low Density Discount**

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

22 23 **4.1.1.6 Tier 2 and Resource Support Services**

24 Tier 2 rates are based on a cost allocation that fully recovers the cost of BPA service to Above-
25 RHWM load. Tier 2 Revenues are based on sales to customers that have elected to have BPA

1 serve their Above-RHWM load. Revenues for FY 2012-2013 are listed in Table 3, line 11, and
2 Documentation Table 4.2, line 17.

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

11 12 **4.1.2 Industrial Power Sales to Direct Service Industrial Customers**

13 BPA sells power to DSIs at the IP rate. Revenues from the IP rate are computed using the
14 product of (1) forecast loads of 340.5aMW for FY 2011-2013, documented in the Power Loads
15 and Resources Study and accompanying Documentation; and (2) the appropriate IP rate from
16 RAM2012. For FY 2011, the revenues for DSI customers are calculated using the WP-10 IP
17 rate. Revenues for FY 2011-2013 are listed in Table 3, line 14, and Documentation Table 4.2,
18 line 20.

19 20 **4.1.3 Pre-Subscription Sales**

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

1 **4.1.4 Short-Term Market Sales**

2 The revenue forecast includes revenues from the sales of surplus energy, which is energy in
3 excess of that required to serve firm loads. For rate development purposes, the forecast of firm
4 FCRPS output is based upon critical (1937) water conditions. FCRPS output, while uncertain, is
5 expected to be greater than under 1937 water conditions, and thus surplus energy sales and
6 revenue result. For FY 2011, the surplus energy revenue included in the revenue forecast
7 consists of current year actuals plus the average of the surplus energy revenues in forecast
8 months computed during RiskMod simulations of 50 games for each of 70 historical water years,
9 for a total of 3,500 games. For FY 2012-2013, the surplus energy revenue is the median of the
10 surplus energy revenues across 3,500 games. In both cases, this power is sold under the FPS rate
11 schedule.

12
13 The revenue forecast for short-term market sales is computed using RiskMod to calculate
14 monthly HLH and LLH energy surpluses for each of the 3,500 games, applying corresponding
15 market prices developed for each game. See Power Risk and Market Price Study, section 2.6.3,
16 and Documentation Table 21. Revenues for FY 2011 – 2013 are shown in Table 3, line 16, and
17 Documentation Table 4.2, line 22.

18
19 **4.1.5 Long-Term Contractual Obligations**

20 Long-term obligation contracts include the WNP-3 Exchange Settlements, a wind energy
21 exchange, capacity and energy exchanges, and a seasonal power exchange. For FY 2011-2013,
22 revenue from these contractual obligations is calculated pursuant to the individual contracts and
23 then summed and added to the forecast as a group. Note that capacity and energy exchanges, as
24 well as the seasonal power exchange, do not generate revenue. Revenue for FY 2011-2013 is
25 listed in Table 3, line 17, and Documentation Table 4.2, line 23.

1 **4.1.6 Canadian Entitlement Return**

2 The Canadian Entitlement Return is an obligation for BPA to deliver power to Canada at the
3 border. No revenues are generated from the delivery of this power, but energy amounts are listed
4 in the revenue forecast to represent this system obligation. The average megawatt deliveries for
5 FY 2011-2013 are listed in Table 3, line 18, and Documentation Table 4.2, line 24.
6

7 **4.1.7 Renewable Energy Certificates**

8 RECs are the environmental attributes corresponding to one megawatthour of generation from a
9 renewable energy resource. BPA sells a portion of the RECs it receives as part of its energy
10 purchases from six wind projects. Under Subscription contracts, 43 preference customers have
11 rights to purchase RECs through FY 2016. BPA forecasts that these preference customers will
12 exercise their full rights up to the limits set in the Subscription contracts; this forecast quantity is
13 about 40 aMW. The price for the RECs for FY 2012-2013 was set outside this rate proceeding
14 pursuant to the terms of the contracts. BPA established the REC price as \$7.50 for FY 2012 and
15 \$8.00 for FY 2013 in May 2011. After eligible preference customers have exercised their
16 contract REC purchase rights, the RECs remaining in BPA's inventory for FY 2012-2013 will be
17 distributed on a pro-rata basis to all CHWM customers based on customers' RHWMs. These
18 RECs are distributed at no additional charge to the customers and do not generate any revenue
19 for Power Services. Revenues for RECs in FY 2012-2013 are listed in Table 3, line 19, and
20 Documentation Table 4.2, line 25.
21

22 **4.1.8 Other Sales**

23 Other sales include revenues from Network Wind Integration Service and from the Storage and
24 Shaping Service, which shapes the variable output for a preference customer's share of a wind
25 project. For FY 2011, 2012, and 2013, the rates for both of these services are set in the
26 respective contracts, then adjusted each fiscal year for inflation. The amount of capacity used as
27 the billing factor for these services is also set in the contracts but remains constant over the

1 length of the contract. Other sales also include miscellaneous revenues from transfer customers
2 and forecast revenues from the Slice True-Up, which is applicable only for FY 2011. Other sales
3 revenue for FY 2011-2013 is listed in Table 3, line 20, and Documentation Table 4.2,
4 lines 26 – 29.

6 **4.2 Revenue Forecast for Miscellaneous Revenues**

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

13
14 Downstream Benefits are revenues BPA receives from utilities that benefit from the coordinated
15 planning and operation of U.S. Army Corps of Engineers and Reclamation upstream storage
16 reservoirs as part of the Pacific Northwest Coordination Agreement. For FY 2011-2013,
17 revenues from downstream benefits are calculated by applying a forecast of the operations and
18 maintenance costs adjusted for inflation to the energy amounts from the most recent study
19 conducted by the Northwest Power Pool (NWPP). The NWPP conducts a study each year on
20 behalf of the utilities to calculate the energy amounts used in determining the downstream
21 benefits.

22
23 Reclamation power for irrigation includes power that has been reserved from the FCRPS for use
24 at Reclamation projects. For revenue forecasting purposes, power that has been reserved to
25 Reclamation irrigation projects is classified as either “Reserved Power” or “Irrigation Pumping
26 Power.” Revenue from Reserved Power for FY 2011, 2012, and 2013 is forecast in equal

1 monthly amounts based on an annual amount that is aggregated for Reclamation projects. The
2 annual aggregated amounts are forecast based on historical information provided by
3 Reclamation. Revenue from Irrigation Pumping Power for FY 2011, 2012, and 2013 is
4 calculated using the forecast irrigation pumping load times the price set in individual contracts.

5
6 Finally, revenues from the Upper Baker project are included. Puget Sound Energy keeps
7 58,000 acre-feet of flood control at this reservoir, which requires it to be held at a lower level
8 during the winter than it would be without flood control, and this creates head losses. On behalf
9 of the Army Corps of Engineers, BPA compensates Puget by delivering non-firm energy and
10 capacity during the flood control season of November through March. In turn, BPA offsets the
11 value of energy and capacity delivered to Puget from the yearly Treasury payment, and the
12 deduction is listed as a revenue from the Corps of Engineers.

13
14 Miscellaneous revenues for FY 2011-2013 are listed in Table 3, line 22, and Documentation
15 Table 4.2, lines 31 – 36.

17 **4.3 Revenue Forecast for Generation Inputs for Ancillary, Control Area, and** 18 **Other Services and Other Inter-Business Line Allocations**

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

1 BPA-05. Revenues are listed in PRS Table 3, line 23, and Documentation Table 4.2, lines 37 –
2 50.

3 4 **4.4 Revenue from Treasury Credits**

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

8 9 **4.4.1 Section 4(h)(10)(C) Credits**

10 Section 4(h)(10)(C) of the Northwest Power Act states that the amounts BPA spends for
11 protecting, enhancing, and mitigating fish and wildlife in the region shall be allocated among the
12 FCRPS hydro projects based on the various project purposes. BPA pays the entirety of the costs
13 relating to the obligations of section 4(h)(10)(C) and is reimbursed by the U.S. Treasury for
14 22.3 percent of the total power purchases BPA is expected to make due to fish mitigation, as well
15 as an equal percentage of program and capital expenses related to the fish and wildlife programs.
16 The 22.3 percent represents the non-power portion of the total FCRPS costs. This credit is
17 treated as Power Services revenue.

18
19 Program and capital expenses relating to the fish and wildlife programs are discussed in the
20 Power Revenue Requirement Study. The methodology for estimating the replacement power
21 purchases resulting from changes in hydro system operations to benefit fish and wildlife is
22 described in section 3.3.1 of the Power Loads and Resources Study. The cost of the increased
23 purchases is estimated using RiskMod and the market price forecast and is included in the Power
24 Risk and Market Price Study, section 2.6.1, and Documentation Table 16. Revenue from
25 4(h)(10)(C) credits is listed in PRS Table 3, line 24, and Documentation Table 4.2, line 52.

1 **4.4.2 Colville Settlement Credits**

2 The Colville Settlement Act Credits are discussed in section 1.2.3 of the Power Revenue
3 Requirement Study. The Colville Settlement Agreement obligates BPA to make annual
4 payments to the Colville Tribes. BPA receives annual credits from the U.S. Treasury against
5 payments due the U.S. Treasury to defray a portion of the costs of making payments to the
6 Colville Tribes. The Treasury credit for the Colville Settlement in FY 2012 and FY 2013 is set
7 by legislation at \$4.6 million per year [Public Law No. 103-436; 108 Stat. 4577, as amended]
8 and is listed in Table 3, line 25, and Documentation Table 4.2, line 53.

9
10 **4.5 Power Purchase Expense Forecast**

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

17
18 **4.5.1 Augmentation Purchase Expense**

19 As explained in section 3.1.2.1.3 of the Power Loads and Resources Study, the forecast of firm
20 FCRPS output is based upon critical (1937) water conditions. The forecast annual firm FCRPS
21 output plus other Federal resources may not be adequate to meet annual average firm loads.
22 Therefore, system augmentation is added to Federal resources to balance firm annual resources
23 with firm annual loads. The Loads and Resources Study projects the need to acquire system
24 augmentation of 176 aMW in FY 2013 to meet firm loads. No augmentation is projected to be
25 necessary for FY 2012. See Power Load and Resources Study, section 4.2.

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

9
10 The expense for the augmentation amounts of 0 aMW in FY 2012 and 176 aMW in FY 2013 is
11 based on projected prices using the AURORAxmp model assuming critical water conditions.
12 See Power Risk and Market Price Study, section 2.6.2, and Documentation Table 17. These
13 prices and the corresponding cost of these augmentation purchases also are documented in
14 Documentation Table 17. Augmentation purchase amounts for FY 2011-2013 are listed in
15 Table 3, line 27, and Documentation, Table 4.2, lines 55 – 57.

16 17 **4.5.2 Balancing Power Purchases**

18 Balancing power purchases are calculated by RiskMod, which finds any monthly HLH and LLH
19 energy deficits by simulations of 50 games in each of the 70 water years, for a total of
20 3,500 games, and applying the corresponding market prices developed for each game. Similar to
21 the treatment of short-term market sales, the mean value for balancing purchases over the
22 3,500 games is reported for FY 2011 for forecast months, added to actual purchases in past
23 months, and the median value is reported for FY 2012-2013. Total balancing purchase expense
24 for FY 2011-2013 is listed in PRS Table 3, line 28, and Documentation Table 4.2, line 58. A full
25 description is available in the Power Risk and Market Price Study, section 2.6.3, and Power Risk
26 and Market Price Study Documentation Table 22.

1 **4.5.3 Other Power Purchases**

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

13
14 The cost of Tier 2 power is also included in other power purchases, as are other miscellaneous
15 contracts. Total other power purchase expense for FY 2011-2013 is listed in Table 3, line 29,
16 and Documentation Table 4.2, line 59.

17
18 **4.6 Summary Table of Power Revenues**

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

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1 **5. RATE SCHEDULES**

2 The power rate schedules establish the applicability of each rate schedule to products that BPA
3 offers, the rates for the products, the billing determinants to which the rates are applied, and
4 references to sections of the GRSPs that apply to each rate schedule. The Power rate schedules
5 described in this section are presented in their entirety in BP-12-A-02B.

6
7 **5.1 Priority Firm Power Rate, PF-12**

8 The PF-12 rate schedule is available for the contract purchase of Firm Requirements Power
9 pursuant to section 5(b) of the Northwest Power Act. Utilities participating in the Residential
10 Exchange Program under section 5(c) of the Northwest Power Act may purchase PF Power
11 pursuant to a Residential Purchase and Sale Agreement or Residential Exchange Program
12 Settlement Implementation Agreement.

13
14 **5.1.1 Firm Requirements Power under a CHWM Contract**

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

1 **5.1.2 Firm Requirements Power under a Contract other than a CHWM Contract (the**
2 **Melded Rate Option)**

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

6
7 **5.1.3 PF Exchange Rate**

8 The PF Exchange rates apply to sales under a Residential Purchase and Sale Agreement or
9 Residential Exchange Program Settlement Implementation Agreement. A utility-specific PF
10 Exchange rate is calculated for each utility purchasing Residential Exchange Program power.
11

12 **5.2 New Resources Firm Power Rate, NR-12**

13 The NR-12 rate is applicable to sales to investor-owned utilities under Northwest Power Act
14 section 5(b) requirements contracts. The NR-12 rate is also applicable to sales to any public
15 body, cooperative, or Federal agency to the extent such power is used to serve any new large
16 single load, as defined by the Northwest Power Act. The NR-12 rate includes energy and
17 demand rates. The NR-12 rate schedule also includes the Unanticipated Load rate.
18

19 **5.3 Industrial Firm Power Rate, IP-12**

20 The IP-12 rate schedule is available for firm power sales to DSIs, as defined by the Northwest
21 Power Act, pursuant to section 5(d). The IP-12 rate includes energy and demand rates. DSIs
22 purchasing power pursuant to the IP-12 rate schedule shall be required to provide the Minimum
23 DSI Operating Reserve – Supplemental.
24

25 **5.4 Firm Power Products and Services Rate, FPS-12**

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

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

6
7 **5.5 General Transfer Service Agreement Rate, GTA-12**

8 The GTA-12 rate schedule includes the GTA Delivery Charge and the Transfer Service
9 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.

1 **6.3 Cost Contributions**

2 Section 7(j) of the Northwest Power Act states that BPA’s rate schedules must indicate the
3 approximate cost contribution of different resource categories to BPA’s rates for the sale of
4 energy and capacity. The rate schedule also must indicate the cost of resources BPA acquires to
5 meet load growth and the relation of such cost to BPA’s average resource cost. See GRSP II.B.
6

7 **6.4 Cost Recovery Adjustment Clause (CRAC)**

8 The CRAC is an upward rate adjustment mechanism that can respond to the financial risks BPA
9 faces before BPA has another chance to set rates during a full rate case. If stated conditions are
10 met, the CRAC will trigger, and a rate increase will go into effect beginning on October 1 of the
11 applicable year. See GRSP II.C and Power Risk and Market Price Study, section 3.2.4.
12

13 **6.5 Dividend Distribution Clause (DDC)**

14 The DDC is a downward rate adjustment mechanism that returns accumulated net revenues to
15 customers when BPA’s cash reserves exceed a pre-defined level. If stated conditions are met,
16 the DDC will trigger, and a rate decrease will go into effect beginning on October 1 of the
17 applicable year. See GRSP II.D and Power Risk and Market Price Study, section 3.2.5.
18

19 **6.6 DSI Reserves Adjustment**

20 In the event that BPA agrees to acquire an additional reserve product from a DSI, this adjustment
21 (1) establishes the mechanism through which BPA compensates the DSI; and (2) places a cap on
22 the unit price of any reserve product to be purchased to ensure that the reserve acquisition is cost
23 effective. See GRSP II.E.
24

25 **6.7 Flexible New Resource Firm Power Rate Option**

26 The Flexible NR rate option, offered at BPA’s discretion, allows NR-12 rates and billing
27 determinants to be modified to accommodate a customer’s request to change the way power is

1 charged under the NR-12 rate schedule. The GRSP describes the factors that will be considered
2 in such modifications. See GRSP II.F.

3 4 **6.8 Flexible Priority Firm Power Rate Option**

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

9 10 **6.9 The NFB Mechanisms**

11 There are two NFB mechanisms that allow BPA to recover additional revenue if financial
12 impacts from a specified set of circumstances in the fish and wildlife arena cause a reduction in
13 Power Services' forecast net revenue. The first mechanism, the NFB Adjustment, could result in
14 an increase in the maximum revenue recoverable under a CRAC. The second mechanism, the
15 Emergency NFB Surcharge, could result in a rate increase within the fiscal year. See GRSP II.K
16 and Power Risk and Market Price Study, section 4.2.

17 18 **6.10 Priority Firm Power (PF) Shaping Option**

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

1 **6.11 REP 7(b)(3) Surcharge Adjustment**

2 The Residential Exchange Program 7(b)(3) surcharge is a utility-specific addition to one of the
3 Base PF Exchange rates that recovers each REP participant's allocated share of rate protection
4 provided pursuant to section 7(b)(2) of the Northwest Power Act. Each REP participant's initial
5 7(b)(3) surcharge is determined in a section 7(i) rate proceeding based on a Base PF Exchange
6 rate and the Average System Cost (ASC) and forecast exchange loads of all utilities assumed in
7 ratemaking to participate in the Residential Exchange Program. Each REP participant's initial
8 7(b)(3) surcharge is displayed in section 6.1 of the PF-12 rate schedule. Each 7(b)(3) surcharge
9 is subject to change during the rate period if a participant's ASC during the rate period due to the
10 addition or removal of a resource from a participant's resource portfolio or the planned addition
11 of a new large single load in the service territory of the participant. The procedures for
12 modifying the 7(b)(3) surcharges of all REP participants are codified in this GRSP. See GRSP
13 II.O for the procedures.

14
15 **6.12 TOCA Adjustment**

16 For each customer purchasing Firm Requirements Power under a CHWM contract, a TOCA for
17 each year of the rate period is calculated in the BP-12 7(i) process. A customer's TOCA for a
18 fiscal year may be adjusted to account for a significant change in the customer's total load, as
19 detailed in GRSP II.T.

20
21 **6.13 Unanticipated Load Service**

22 Unanticipated Load Service (ULS) applies to any request for Firm Requirements Power received
23 after February 1, 2011, that results in an unanticipated increase in a customer's load placed on
24 BPA during the FY 2012-2013 rate period. Contractual obligations that result from a request for
25 service under section 9(i) of the Northwest Power Act also will be considered ULS. ULS also
26 may apply to a customer that adds load through retail access, including load that was once served
27 by the customer and returns from under retail access. See GRSP II.U.

1 **6.14 Unauthorized Increase Charges**

2 The Unauthorized Increase (UAI) charge is a penalty charge to customers taking more power
3 from BPA than they are contractually entitled to take. The UAI demand charge is 1.25 times the
4 applicable monthly demand charge. The UAI energy charge is the greater of 150 mills/kWh or
5 2.0 times the highest hourly Powerdex Mid-C Index price for firm power for the month. See
6 GRSP II.V.

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1 **7. SLICE**

2 **7.1 Slice True-Up Adjustment**

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

7
8 **7.2 Composite Cost Pool True-Up**

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

- 12 (1) subtracting:
- 13 (i) the forecast annual expenses, revenue credits, and adjustments allocated to
 - 14 the Composite Cost Pool for the applicable fiscal year of the rate period from
 - 15 (ii) the actual expenses, revenue credits, and adjustments in the applicable fiscal
 - 16 year of the rate period that are allocable to the Composite cost pool;
- 17 (2) dividing the difference determined in (1) above by the sum of the actual
- 18 Composite cost pool TOCAs for that fiscal year (TOCAs are determined in
- 19 accordance with TRM section 5.1.1 based on the Annual Net Requirement for
- 20 Slice customers and computed consistent with the Load Shaping True-Up
- 21 methodology set forth in TRM section 5.2.4.1 for Load Following customers);
- 22 and
- 23 (3) multiplying the quotient by each Slice customer's Slice Percentage for the
- 24 applicable fiscal year.
- 25

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

13 **7.3 Treatment of Certain Expenses, Revenue Credits, and Adjustments in the** 14 **Composite Cost Pool True-Up**

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

18 **7.3.1 System Augmentation Expenses**

19 System augmentation expenses are included in the FY 2012-2013 Composite cost pool. Part of
20 these augmentation expenses is a cost for service to non-Slice customers' Above-RHWL load
21 that is served at Load Shaping rates. For a description of these system augmentation expenses,
22 see section 3.1.3.3.

23
24 System augmentation expenses will not be subject to the Composite Cost Pool True-Up.
25 However, implicit in the Composite Cost Pool True-Up of the firm surplus and secondary
26 adjustment for Unused RHWL, and implicit in the Composite Cost Pool True-Up for the DSI
27 revenue credit, are adjustments that reflect the effects of additional power purchases (or lack

1 thereof) or additional power sales to the market. See section 3.1.3.2 for a description of the
2 treatment of the firm surplus and secondary adjustment for unused RHW and the DSI revenue
3 credit for Composite Cost Pool True-Up purposes.

4
5 BPA's purchases of output from the Klondike III resource is a Tier 1 augmentation expense, and
6 the Composite cost pool includes the cost of Resource Support Services and Resource Shaping
7 Charges to shape the generation output of Klondike III into a flat annual block of power.
8 Because the RSS and RSC charges financially convert the variable output of Klondike III to a
9 firm annual block of power, the augmentation expense and RSS and RSC costs associated with
10 generation output from the Klondike III resource will not be subject to the Composite Cost Pool
11 True-Up.

12 13 **7.3.2 Balancing Augmentation Adjustment**

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

19 20 **7.3.3 Firm Surplus and Secondary Adjustment from Unused RHW**

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

1 TOCAs from the sum of forecast TOCAs. The calculation of the actual firm surplus and
2 secondary adjustment reflects the fact that when the sum of actual TOCAs is greater than the
3 sum of forecast TOCAs, additional power is sold to customers at the Composite Customer rate,
4 and it is assumed that additional costs are incurred in the form of forgone market sales or
5 increased power purchases.

6
7 The calculation of the actual firm surplus and secondary adjustment reflects the fact that when
8 the sum of actual TOCAs is less than the sum of forecast TOCAs, less power is sold to
9 customers at the Composite Customer rate, and it is assumed that more power is sold in the
10 market or fewer power purchase costs are incurred.

11 12 **7.3.4 DSI Revenue Credit**

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

16
17 For purposes of the Composite Cost Pool True-Up, an actual DSI revenue credit will be
18 calculated. For details on how the actual DSI revenue credit will be calculated, see
19 GRSP II.R.1.(b).

20
21 The calculation of the actual DSI revenue credit starts with the forecast DSI revenue credit and
22 makes an adjustment to the forecast to calculate the actual DSI revenue credit. When the actual
23 DSI sales are greater than the rate case forecast DSI sales, it is assumed that additional power is
24 sold to the DSIs at the IP rate, and additional costs are incurred in the form of forgone market
25 sales or increased power purchases. The adjustment to the forecast DSI revenue credit reflects

1 the revenues from the additional power sold to the DSIs and the additional costs that are
2 incurred.

3
4 When the actual DSI sales are less than the rate case forecast DSI sales, it is assumed that less
5 power is sold to DSIs at the IP rate and more power is sold in the market, or it is assumed that
6 such power may be used to meet BPA obligations so that fewer power purchase costs are
7 incurred. The adjustment to the forecast DSI revenue credit will reflect these effects. The
8 adjustment will also include any DSI take-or-pay revenues, if applicable.

9 10 **7.3.5 Unspent Green Energy Premium Revenues**

11 For ratesetting purposes, a forecast amount of unspent GEP revenue balance remaining at the end
12 of FY 2011 will be applied as a contra-expense in FY 2012-2013 against certain forecast
13 expenses. See 2010 Integrated Program Review Final Close-Out Letter and Report, October 27,
14 2010. The contra-expense will be subject to the Composite Cost Pool True-Up. The contra-
15 expense included in the Composite cost pool for ratesetting purposes is a forecast of the
16 remaining balance of unspent GEP revenues as of the end of FY 2011. The actual remaining
17 balance of unspent GEP revenues will be calculated after audited actual financial data is
18 available to BPA for FY 2011. The difference between the actual unspent GEP revenues and the
19 forecast of the contra-expense included in the Composite cost pool for ratesetting purposes will
20 be tracked for Composite Cost Pool True-Up purposes. In any given fiscal year, the actual
21 contra-expense cannot exceed the actual eligible expenses.

22
23 GEP revenues earned in FY 2012-2013 are a revenue credit in the FY 2012-2013 Composite cost
24 pool. This revenue credit will be subject to the Composite Cost Pool True-Up.

1 **7.3.6 Interest Earned on the Bonneville Fund**

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

7
8 Table 4 displays the circumstances and the related adjustments to the size of the base amount
9 (\$495.6 million). The revised amount is \$496.40 million.

10
11 The amounts contained in Table 4 have not been shared with or collected from Slice customers
12 through a prior Slice True-Up, so these amounts will be adjustments to the size of the base
13 amount of financial reserves. The payments or funds that BPA received are reflected as negative
14 amounts in Table 4 and will increase the size of the base amount of financial reserves. BPA's
15 payments for settlements or judgments, and BPA's write-off of bad debt expense, are reflected as
16 positive amounts in Table 4 and will decrease the size of the base amount of financial reserves.

17
18 To the extent that BPA receives payments or makes payments during a fiscal year of the
19 FY 2012-2013 rate period and the payments can be categorized into one of the types of receipts
20 or payments described in the TRM, and those receipts or payments have not been proportionally
21 allocated to Slice customers through their Slice True-Up Adjustment Charges during the rate
22 period, then BPA will make an adjustment to the size of the base amount of financial reserves.

23
24 The interest credit on the financial reserves amount will be subject to the Composite Cost Pool
25 True-Up. The actual interest credit calculated on the base amount of financial reserves can
26 change from forecast interest credit due to changes in interest credit calculation factors from

1 forecast factors. See Revenue Requirement Study Documentation, section 5, for a description of
2 how the interest credit calculation factors can change from final rate case studies.

4 **7.3.7 Bad Debt Expenses**

5 Bad debt expenses could be allocated between the Composite cost pool and the Non-Slice cost
6 pool. TRM, Table 2A. There is no forecast bad debt expense for the FY 2012-2013 period for
7 ratesetting purposes. If a bad debt expense is identified and accounted for in BPA's actual
8 audited financial reports for a given fiscal year, there would first be a determination of whether
9 the expense would be included in the actual expenses and revenue credits that are allocable to the
10 Composite cost pool in the applicable fiscal year of the rate period. If so, then the expense may
11 be included for purposes of the Composite Cost Pool True-Up, and the bad debt expense would
12 be allocated according to the principle of cost causation. TRM section 2.1.

13
14 Any bad debt expense associated with a sale to any customer that purchased Federal power
15 exclusively at the FPS-02, FPS-07, FPS-07S, FPS-10, and FPS-12 rates would be excluded for
16 Composite Cost Pool True-Up purposes. Bad debt expenses associated with sales of power at
17 only these FPS rates are related solely to BPA's sales of surplus power after the inception of the
18 Slice product and not to sales of requirements power. The expenses and revenues from such
19 sales are attributable to BPA's marketing of secondary energy after the inception of the Slice
20 product, and are included in the Non-Slice cost pool. See TRM section 2.2.3.

21
22 Any bad debt expense associated with a sale to a customer that purchases power at only the PF or
23 IP rate will be included for purposes of the Composite Cost Pool True-Up. The allocation to the
24 Composite cost pool of any bad debt expense associated with a sale to a customer that purchases
25 power at both the PF rate and the FPS rate, or a sale to a customer that purchases power at both
26 the IP rate and the FPS rate, will be entirely contingent on the facts and circumstances of the

1 particular instance of a full or partial non-payment of a power bill. BPA will not determine a
2 particular cost treatment in the absence of specific information on the transaction to guide this
3 determination. There have been no bad debt allocations at issue since BPA's decisions to
4 include any bad debt expenses arising from mixed transactions in the Slice True-Up Adjustment
5 Charge calculation. BPA will defer any determination of allocation to the Composite cost pool
6 until an instance of bad debt expenses arises.

7
8 Any future bad debt expense related to write-offs of any outstanding California Independent
9 System Operator (CAISO) or California Power Exchange (Cal PX) receivables for transactions
10 prior to October 1, 2001, will be excluded for Composite Cost Pool True-Up purposes. Such bad
11 debt expenses were specifically excluded as part of the Slice Settlement Agreement (07PB-
12 12273), which was effective until September 30, 2011. This exclusion is proposed for
13 continuation for the BP-12 rate period.

14
15 Any bad debt expenses related to write-offs of any outstanding receivables arising out of FPS
16 power sales transactions (other than with CAISO or Cal PX) prior to October 1, 2001, will be
17 included for Composite Cost Pool True-Up purposes. Such bad debt expenses were not
18 specifically excluded as part of the Slice Settlement Agreement. Such bad debt expenses will be
19 included for Composite Cost Pool True-Up purposes because FPS power sales transactions prior
20 to October 1, 2001, benefited all customers, as there was no Slice product prior to that date.

21
22 Revenue recoveries of bad debt expenses will be included for Composite Cost Pool True-Up
23 purposes if Slice customers paid for the bad debt expense through their Subscription Slice
24 True-Up Adjustment Charge or RD Slice True-Up Adjustment Charge.

25
26 For the categories of bad debt expenses specifically excluded from the Subscription Slice
27 True-Up Adjustment Charges since FY 2002, any related revenue recoveries of such bad debt

1 expenses will be excluded for purposes of the Composite Cost Pool True-Up. This treatment is
2 consistent with cost causation principles. See TRM section 2.1. Since Slice customers did not
3 share in these bad debt expenses, Slice customers will not share in any related revenue
4 recoveries.

6 **7.3.8 Settlement or Judgment Amounts**

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

14 **7.3.9 Transmission Costs for Designated BPA System Obligations**

15 Transmission and Ancillary Services expenses are allocated between the Composite cost pool
16 and the Non-Slice cost pool. See TRM Table 2A.

17
18 The Transmission and Ancillary Services expenses associated with Designated BPA System
19 Obligations are allocated to the Composite cost pool. Such Transmission and Ancillary Services
20 expenses will not be subject to the Composite Cost Pool True-Up.

21
22 Transmission reservations are set aside for non-discretionary obligations (*i.e.*, Designated BPA
23 System Obligations). Since Power Services does not know the actual amounts of transmission
24 usage until the preschedule period for such obligations, the transmission reservations for those
25 obligations are purchased based on the maximum need for the year. Therefore, it is appropriate

1 to include the forecast cost of the reservations for Designated BPA System Obligations in the
2 Composite Cost Pool, and such costs will not be subject to the Composite Cost Pool True-Up.

3
4 Any revenue from resales of transmission that appear to be the result of BPA sales of unused
5 transmission inventory associated with set-aside transmission will be excluded for Composite
6 Cost Pool True-Up purposes. Such revenues will be excluded from the Composite Cost Pool
7 True-Up to be consistent with the principle of no Composite Cost Pool True-Up of transmission
8 expenses for Designated BPA System Obligations. Since the cost of additional transmission
9 purchased (or of using non-Slice transmission inventory) to serve Designated BPA System
10 Obligations in excess of what was forecast in the rate case will not be included in the Composite
11 Cost Pool True-Up, such principle requires that revenues from sales of surplus transmission
12 inventory also be excluded from the Composite Cost Pool True-Up.

14 **7.3.10 Transmission Loss Adjustment**

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

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

23 **7.3.11 Resource Support Services Revenue Credit**

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

1 **7.3.12 Tier 2 Rate Adjustments**

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

6
7 The Tier 2 overhead cost adder is an adjustment for administrative costs incurred by Power
8 Services. See section 3.1.7.1. The Tier 2 overhead cost adder will be included in the Composite
9 cost pool. This adjustment will be estimated for ratesetting purposes and not subject to the
10 Composite Cost Pool True-Up.

11
12 The Tier 2 risk adder is an adjustment for any risks associated with resource costs that Power
13 Services acquires for service to Tier 2 load. This adjustment is zero for the FY 2012-2013 rate
14 period because no risk mitigation treatment is necessary. See section 3.1.7.4. This adjustment
15 will not be subject to the Composite Cost Pool True-Up.

16
17 The Tier 2 Transmission Scheduling Service cost adder is an adjustment for administrative costs
18 incurred by Power Services. For a description of this adjustment, see section 3.1.7.2. The
19 forecast of this adjustment is included in the RSS revenue credit. This adjustment will not be
20 subject to the Composite Cost Pool True-Up.

21 **7.3.13 Residential Exchange Program Expense**

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

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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.

1 **8. AVERAGE SYSTEM COSTS**

2 **8.1 Overview of Average System Cost and the Residential Exchange Program**

3 One of the components of the REP is the participating utilities' Average System Costs (ASC),
4 which are determined in a separate ASC Review Process that BPA conducts pursuant to the
5 substantive and procedural requirements of the 2008 ASC Methodology (ASCM). *See* 2008
6 ASCM, 18 C.F.R. § 301, *et seq.* The 2008 ASCM is an administrative rule that governs BPA's
7 calculation of ASCs. The Federal Energy Regulatory Commission granted final approval to the
8 2008 ASCM on September 4, 2009.

9
10 BPA has adopted the 2012 REP Settlement. The Settlement establishes a fixed stream of REP
11 benefits that are payable to the IOUs for the period beginning in FY 2012 and ending in
12 FY 2028. Distribution of the REP benefits under the Settlement will continue as under the
13 traditional REP. BPA will compare the IOUs' respective ASCs with their PF Exchange rates
14 and, if the difference is positive, multiply the difference by the IOUs' exchange loads. Thus,
15 IOUs' ASCs and exchange loads for FY 2012-2013 are needed to determine the REP benefits
16 provided to individual IOU participants consistent with the Settlement. Similarly, for the two
17 COUs participating in the REP, BPA will compare their respective ASCs with their PF Exchange
18 rates and, if the difference is positive, multiply the difference by their exchange loads. The COU
19 REP benefits are in addition to the fixed stream of IOU REP benefits under the Settlement.

20
21 **8.2 Overview of ASC Determinations**

22 An ASC is calculated by dividing a utility's allowable resource costs (Contract System Cost) by
23 the utility's allowable load (Contract System Load). The quotient is the utility's ASC (\$/MWh).
24 Contract System Cost is the sum of the utility's allowable generation- and transmission-related
25 costs and overheads. Contract System Load is the sum of the total retail sales of a utility, as

1 measured at the meter, plus distribution losses, less any New Large Single Loads (NLSLs), if
2 applicable.

3
4 The ASCs used in the BP-12 rates were determined in Final ASC Reports published on July 25,
5 2011. These Final ASC Reports reflect the utilities' ASCs for the BP-12 rate period. Final ASC
6 Reports were issued for eight utilities: Avista Utilities, Idaho Power Company, NorthWestern
7 Energy, PacifiCorp, Portland General Electric, Puget Sound Energy, Clark County PUD, and
8 Snohomish County PUD.

9
10 Under the 2008 ASCM, the actual ASC for each utility may change if the utility adds a new
11 resource, retires an existing resource, or adds an NLSL. The revised ASC takes effect in the
12 month after a new resource comes on line, an existing resource is retired, or a new NLSL begins
13 taking service.

14
15 Under the 2012 REP Settlement, participating IOUs agreed to refrain from filing for ASC
16 revisions based upon new resources coming on line or retiring during the Exchange Period (the
17 Exchange Period is identical to the rate period). Under the REP Settlement, the ASCs that are
18 effective on the first day of the rate period would persist throughout the Exchange Period.
19 Therefore, "day-one" ASCs have been developed for use in establishing rates under the REP
20 Settlement.

21
22 Two utilities have new resources or new NLSLs that are scheduled to begin operation between
23 the date of the Final ASC Reports (July 25, 2011) and the start of the Exchange Period. The
24 day-one ASCs used for the BP-12 rates assume that these new resources or new NLSLs are
25 operating prior to the start of the Exchange Period. If they fail to do so, then the actual ASCs
26 and individual utility benefits will differ from the BP-12 values. If there is a change to any ASC
27 used in setting rates, utility-specific 7(b)(3) surcharges for all REP participants will be

1 recomputed using GRSP II.O. The day-one ASCs are shown in Table 2.1.3 of the
2 Documentation.

3 4 **8.3 BP-12 Residential and Small Farm Exchange Loads**

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

8
9 Utilities intending to participate in the REP for FY 2012-2013 were required to submit with their
10 ASC filings in June 2010 a forecast of their residential and small farm sales (reflecting their
11 exchange loads), measured at the retail meter, for FY 2012-2017. The forecast REP exchange
12 loads for FY 2012-2013 were increased to reflect distribution losses.

13
14 Under the 2012 REP Settlement, participating IOUs agreed to use a two-year historical average
15 for determining the exchange load used to calculate REP benefits, referred to as Residential
16 Load. Residential Load is determined in the BP-12 ratemaking process pursuant to the terms of
17 the Settlement and published in GRSP II.N. For the COUs, the FY 2012-2013 exchange load
18 forecasts are based on the exchange load information provided by the COUs in the ASC Review
19 Processes. COU REP benefits will be paid on actual residential and small farm sales for each
20 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)	Bonnors 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	OAD4101016	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)						
Reasons for adjustments								
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 positive, 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 essentially 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.

