2029 PUBLIC RATE DESIGN METHODOLOGY

Rough Draft

BP-26-E-01

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ATTACHMENTS (not included with Rough Draft)

1 BACKGROUND AND PURPOSE

Chapter objectives: Describe legal and rate foundation for Tiered rates; affirm a two-year rate period.

Section 7(b)(1) of the Northwest Power Act requires BPA to establish a "rate or rates" for the sale of firm electric power to meet the "general requirements" load of public body, cooperative, and federal agency customers (public customers, or "Publics"). 16 U.S.C. § 839e(b)(1). The public customers' "general requirements" load is the electric power they purchase from the Administrator under Section 5(b) of the Northwest Power Act, excluding new large single loads. *Id.* at § 839e(b)(4).

This Public Rate Design Methodology (PRDM) is the rate methodology BPA will use to develop the Section 7(b) rate for the general requirements of Publics with CHWM Contracts. For purposes of the PRDM, the Section 7(b) rate, is referred to as the Priority Firm Power (PF) rate. Consistent with Section 7(b) and the rate design discretion afforded to the Administrator by Section 7(e) of the Northwest Power Act, the PF rate design, as described herein, will be composed of two tiers. The first tier (Tier 1 Rates) sets rates designed to recover the costs associated with serving a public customer's general requirements load that is designated as Contract High Water Mark (CHWM) Load under the terms of the public customer's Power Sales Contract. The second tier (Tier 2 Rates) sets rates designed to recover the costs associated with serving a public customer's general requirements load that is designated as Above-Contract High Water Mark (Above-CHWM) Load under the terms of the public customer's Power Sales Contract. The PRDM specifies how PF rates will be developed by BPA under these two tiers, with the objective of ensuring, to the maximum extent practical, that Tier 1 Rates do not include costs of serving a public customer's Above-CHWM Load.

Other (not Core) rate adjustments, charges, and special provisions, as well as the rate design applicable to products and services not included in the PRDM, will be established in each 7(i) Process.

1.1 Two-Year Rate Periods

BPA determinations of specific rate levels will be made in a manner consistent with the PRDM in the respective 7(i) Process during the term of this PRDM. Under the PRDM, BPA will set power rates for Rate Periods no longer than two years.

1.2 Duration of the PRDM

This PRDM shall be effective October 1, 2028, and shall apply until all contracts that sell power at rates set pursuant to the PRDM have expired.

1.3 Scope of PRDM References and Descriptions

The PRDM addresses cost allocation and rate design of the PF rates applicable to the general requirements of public customers taking service under a CHWM Contract. It does not address the cost allocation or rate design of any other rate. Throughout the PRDM, there are references to BPA's power costs in aggregate, or to elements of BPA's power costs that are not recovered solely through the PF rates applicable to the PRDM. The PRDM states that all costs BPA functionalizes to power will be included in the Revenue Requirement Table. *See* Section 2.2. Each line item on the Revenue Requirement Table will be allocated to matching line items on Allocated Cost Tables established for each rate pool. The Cost Pools on the Allocated Cost Table for the PF Preference rate pool will establish the treatment of costs to be recovered through either the various Tier 1 Rates or the various Tier 2 Rates. These Cost Pools on the Allocated Tiered Cost Table do not address BPA power costs on the Revenue Requirement Table that are to be recovered through (allocated to) other rates, such as the New Resources Firm Power (NR) rate or the Industrial Firm Power (IP) rate.

To the extent the PRDM refers to costs beyond those to be recovered through tiered PF rates, this is not intended to imply that tiered PF rates will be designed to recover those costs. Rather, these statements should be understood in the context of the sequential process. That is, BPA will first determine its overall total system costs, then functionalize those costs to Power Services and Transmission Services, and then allocate the total Power system costs among its applicable rates *(e.g.,* PF, PF Exchange, IP, NR, FPS, others), in accordance with the rate directives of Section 7 of the Northwest Power Act. The provisions of the PRDM apply after this allocation, and only apply to the portion of costs and revenues allocated to PF rate(s) receiving service under a CHWM Contract. See Figure 2-1. The PRDM does not address issues relating to other BPA rates, except the PF Exchange Rate for Publics with CHWM Contracts as described in Section 8.3.

2 COST ALLOCATIONS

Chapter objectives: Revise section on BPA Earned Interest Fund reflecting increasing disconnect between early contributions, current product makeup and switching, and simplification of internal systems and processes.

The PRDM specifies how costs will be allocated to the Tier 1 Cost Pools and the Tier 2 Cost Pools that are used to calculate the Tier 1 and Tier 2 Rates. BPA will set all its rates, including the Tier 1 and Tier 2 Rates, in each 7(i) Process.

The costs allocated to the Tier 1 Cost Pools will be separate from the costs allocated to the Tier 2 Cost Pools. The Tier 1 Rates will be applicable to power purchased up to a customer's CHWM Amount, and the Tier 2 Rates will be applicable to power purchased in excess of a customer's CHWM Amount (also referred to as Above-CHWM Amount).

2.1 Cost Allocation Principles

The following principles were applied in developing the PRDM Cost Allocation Method and will be used for allocating costs that are not specifically addressed in the PRDM.

1) Tiering is a ratemaking construct implemented through an allocation of costs rather than an allocation of power.
2) Costs not otherwise expressly allocated in the PRDM will be allocated to Cost Pools based on the principles of cost causation, meaning the costs will be allocated to the Cost Pool(s) that benefit from or cause such costs.
3) Tier 1 Costs will be kept separate and distinct from Tier 2 Costs. Tier 1 Costs will be recovered through the Tier 1 Rates. Tier 2 Costs will be recovered through Tier 2 Rates, except when necessary to ensure BPA's cost recovery during a Rate Period or to conform to court ruling as provided for in Chapter 9.

4) Tier 2 Cost Pools will be kept separate from one another. Each Tier 2 Rate will recover only the costs of the applicable Tier 2 Cost Pool. BPA will seek to recover all costs of the applicable Tier 2 Cost Pool from customers purchasing power from that Tier 2 Cost Pool before proposing any reallocation of costs to the Composite Cost Pool.
5) Cost separation between the Cost Pools will not affect the operation or dispatch of the FCRPS.
6) The ratemaking separation of costs between Tier 1 and Tier 2 Cost Pools, and among the Tier 2 Cost Pools, will not necessarily be the same as BPA's accounting treatment of the costs. When differences arise between ratemaking and accounting, the ratemaking allocations determined in accordance with this chapter will govern BPA's ratemaking.
7) BPA's allocation of costs among the Composite, Non-Slice, and Slice Cost Pools will recognize the types of costs distinct to the type of service associated with each Cost Pool.
8) The public customers have entered into a long-term CHWM Contract with BPA, which commits the public customer to purchase (and BPA to supply) electric power for the duration of the contract (as described therein) at rates that recover BPA's total system costs consistent with Section 7 of the Northwest Power Act. In view of this long-term commitment, and potential future long-term commitments incorporating the PRDM, the revenues and costs associated with the sales of secondary energy be treated in a manner that recognizes BPA's long-standing treatment of these revenues. Specifically:
    a) all revenues forecast by BPA from its sale of secondary energy produced by the Federal Base System and other resources acquired by the Administrator will continue to be credited to power rates pursuant to Northwest Power Act

Section 7(g) against costs that are properly allocated to rates for recovery from sales of power for use within the region; and

b) costs and benefits of the sale of or inability to sell excess electric power allocated under Section 7(g) of the Northwest Power Act will be allocated to the Cost Pools to which the costs of the resources that generate such excess electric power are allocated, consistent with Section 7 of the Northwest Power Act.

9) The tiered rate treatment described in this PRDM will preserve consistency with generally accepted ratemaking principles.

10) The allocation of costs and revenues as described in the PRDM does not prescribe any particular conveyance of environmental and/or other attributes associated with power purchased from BPA.

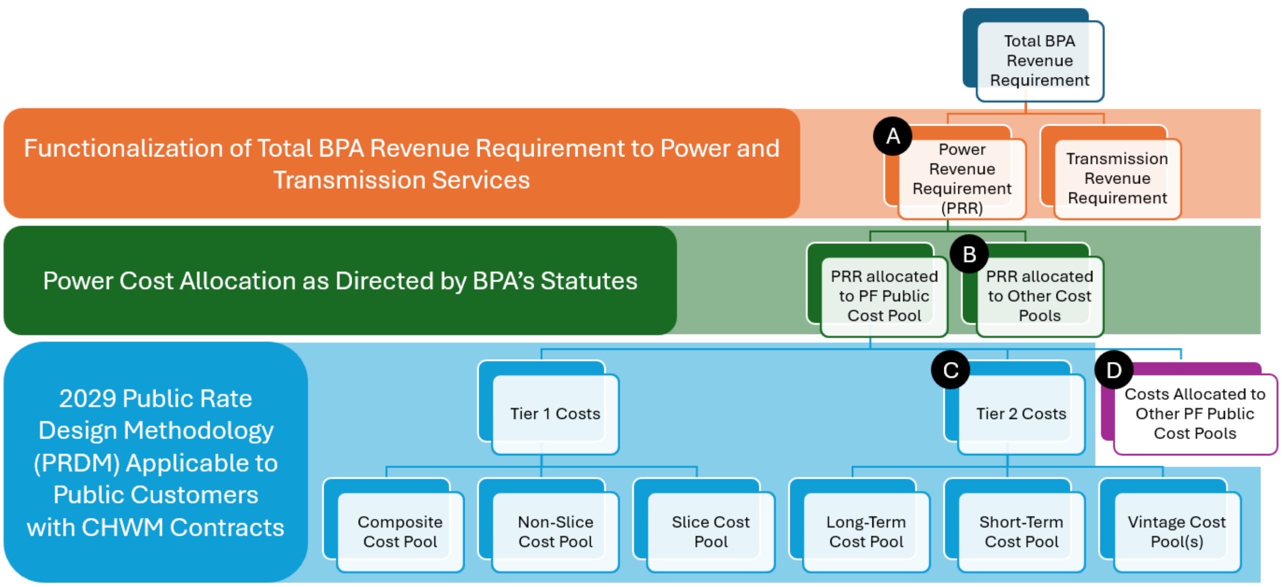
2.2 Cost Allocation Method and Allocated Tiered Cost

In each 7(i) Process under the PRDM, BPA will allocate Tier 1 Costs among three Tier 1 Cost Pools for determining Tier 1 Rates, and Tier 2 Costs to one or more Tier 2 Cost Pools corresponding to each Tier 2 Rate Alternative. The Tier 1 Cost Pools are the Composite Cost Pool, Slice Cost Pool, and Non-Slice Cost Pool. The allocation of costs to Cost Pools is a ratemaking exercise that is performed in a 7(i) Process according to the directives in Section 7 of the Northwest Power Act.

The Tier 1 Cost Pools will be determined by starting with the Revenue Requirement functionalized to Power and subtracting the portion of that Revenue Requirement recovered from BPA's other power rates, as directed by BPA's statutes. The remaining Revenue Requirement will be recovered from the PF Public Cost Pool.

The portion of the PF Public Cost Pool that is allocated to the Tier 2 Cost Pools, as well as any portion of the PF Public Cost Pool allocated to non-CHWM PF Public Customers, will then be subtracted from the PF Public Cost Pool. The remaining portion of the PF Public Cost Pool will be allocated to Tier 1 Cost Pools. The Tier 1 Costs are then sub-allocated to the three Tier 1 Cost Pools—the Composite Cost Pool, the Slice Cost Pool, and the Non-Slice Cost Pool. (See Figure 2.1 below)

Figure 2-1
Soup-to-Nuts Power Cost Allocation



Consistent with Figure 2-1 above, BPA's Tier 1 Costs are calculated as:

$$Tier\ 1\ Costs = A - B - C - D$$

Where:

A = The portion of BPA's total Revenue Requirement functionalized to Power Services.

B = The portion of Power Services' Revenue Requirement allocated to BPA's other Cost Pools as directed by BPA's Statutes.

C = The portion of the PF Public Cost Pool identified as Tier 2 Costs.

D = The portion of the PF Public Cost Pool allocated to other non-CHWM PF Public Customers.

2.2.1 Cost Allocation Proof

The mathematical, illustrative, summarizing, and accounting methods used to solve for Tier 1 and Tier 2 Rates in each 7(i) Process may vary. Therefore, to ensure that the PF Public rates are set in accordance with Section 7 of the Northwest Power Act and the Principles in Section 2.1 of this Chapter, BPA will conduct a cost allocation proof in every 7(i) Process. The proof will verify that the total costs recovered from all PF Public rates is equal to only the portion of BPA's total power costs that, in accordance with Section 7 of the Northwest Power Act, are to be recovered from PF Public rates.

2.2.1.1 The Composite Cost Pool

Section A of the Allocated Tiered Cost Table sets out the categories of costs that are allocated to the Composite Cost Pool, including all Tier 1 Costs and Tier 1 Credits functionalized by BPA to Power, except for any Tier 1 Costs or Tier 1 Credits that BPA has determined meet the specified criteria for inclusion in either the Slice Cost Pool or the Non-Slice Cost Pool, as set forth in Sections 2.2.3.2 and 2.2.3.3. The administrative costs (primarily staffing costs) of surplus marketing and administering all CHWM Contracts and rates, including potential future contracts that are applicable to the PRDM, will be allocated to the Composite Cost Pool.

2.2.1.2 The Slice Cost Pool

Section B of the Allocated Tiered Cost Table is designed to include the costs that are allocated to the Slice Cost Pool, including all Tier 1 Costs and Tier 1 Credits that are specifically and uniquely attributable to the Slice product. If, during the term of CHWM Contracts (including potential future contracts applicable to the PRDM), BPA undertakes actions that are specifically and uniquely attributable to the Slice Product (for example, customer-requested software enhancements specific to the Slice Product), then BPA will allocate the costs of undertaking these actions to the Slice Cost Pool unless BPA and the Slice customers have made separate payment arrangements. Such costs would be treated as New Expenses under the PRDM for allocation purposes. Similarly, if in the future there are New Credits attributable to the Slice Product only, these New Credits would be allocated to the Slice Cost Pool.

2.2.1.3 The Non-Slice Cost Pool

Section C of the Allocated Tiered Cost Table sets out the categories of costs that are allocated to the Non-Slice Cost Pool, including all Tier 1 Costs and Tier 1 Credits that are specifically and uniquely attributable to the Load Following or Block Products. The Non-Slice Cost Pool includes the costs and credits of converting resource output into load service (e.g., Balancing Power Purchases); the costs of Tier 1 risk mitigation not recovered through rates for the Slice Product; and the costs or credits arising from Non-Slice Tier 1 capacity acquisitions, see Section 3.5. The Non-Slice Cost Pool also includes the Tier 1 Secondary Energy Credit, which includes any costs or credits specifically attributable to BPA's marketing of Tier 1 Secondary Energy and excludes administrative costs allocated to the Composite Cost Pool.

2.2.1.4 Tier 2 Cost Pools

Section D of the Allocated Tiered Cost Table sets out the costs that are allocated to the Tier 2 Cost Pools. Such costs include all Tier 2 Costs that are attributable to resources and services that BPA forecasts for ratemaking purposes to use for serving load at a Tier 2 Rate. Included in Table 2, Section D, are RSS costs used to set the Tier 2 Rates. BPA will include a uniform adder, the Overhead Cost Adder, in the Tier 2 Cost Pools. BPA will credit the forecast revenue from the Overhead Cost Adder to the Composite Cost Pool. See Section 5.2 for a fuller discussion of costs allocated to Tier 2 Cost Pools and Section 5.2.3 for discussion of the Overhead Cost Adder. Any uses of Tier 1 System Resources to serve load at a Tier 2 Rate, as forecast for ratemaking purposes, will be priced in accordance with Chapter 5.

2.2.2 Allocated Tiered Cost Table

The Allocated Tiered Cost Table, Table 2, sets out the cost categories that will be used for allocating costs in each 7(i) Process. Any changes to the Allocated Tiered Cost Table to accommodate New Expenses or New Credits will be made pursuant to Section 2.3. Any changes to the Allocated Tiered Cost Table to accommodate a need to allocate a Tier 2 Cost to a Tier 1 Cost Pool will be pursuant to Section 2.6. All other changes to the Allocated Tiered Cost Table will be pursuant to Chapter 9. The addition of new Tier 2 Cost Pools will not be considered a change to the Allocated Tiered Cost Table for purposes of Chapter 9.

BPA will conform the description or grouping of costs in the Allocated Tiered Cost Table to the grouping of costs in the Power Services Statement of Revenues and Expenses, but changes to line item descriptions or groupings in the Power Services Statement of Revenues and Expenses will not change the Cost Pools to which the underlying costs are assigned. If modifications to BPA's Power Services Statement of Revenues and Expenses change the categorization of costs, then the manner of maintaining the separation of costs for purposes of the PRDM will be addressed in the next 7(i) Process following the modification. Such modifications will not change the underlying allocation of costs to the respective Cost Pools, which form the basis for setting Tier 1 and Tier 2 Rates.

2.3 Inclusion of New Expenses or New Credits

BPA will allocate New Expenses or New Credits to the Cost Pools based on the cost allocation principles in Section 2.1. BPA will propose an allocation of the New Expenses and New Credits to the appropriate Cost Pools in a 7(i) Process.

2.4 Tier 1 Secondary Energy Credit

The Slice Product includes an advance sale of surplus energy, which is delivered when and if available. As a consequence, the Composite Cost Pool and Slice Cost Pool do not contain any cost or credit, except administrative costs, associated with Tier 1 Secondary Energy. When Load Following and Block Products do not receive Tier 1 Secondary Energy as an advance sale of surplus energy, the Non-Slice Cost Pool will be allocated a Tier 1 Secondary Energy Credit. Such Tier 1 Secondary Energy Credit can take the form of a fixed credit based on forecast, a variable credit based on actuals, or a combination of the two. Notwithstanding any other provision in this PRDM, and irrespective of whether BPA allocates Section 7(b)(2) trigger amounts to BPA surplus sales, BPA will seek to ensure comparable treatment with respect to Tier 1 Secondary Energy as between the Slice and Non-Slice Cost Pools.

Tier 1 Secondary Energy Credit associated with the Unused CHWM will be included in the Composite Cost Pool rather than the Non-Slice Cost Pool. BPA may also propose in a 7(i)

Process that portions of the Tier 1 Secondary Energy Credit be reallocated to Composite Cost Pool as supported by Section 2.1, such as when a market, operational, or other decision causes a portion of the advanced sale of secondary associated with the Slice Product to otherwise be credited to the Non-Slice Cost Pool.

2.5 Interest Earned on the Bonneville Fund

BPA will allocate to the Non-Slice Cost Pool a credit equal to the total anticipated credit earned on Bonneville Fund balances attributed to the Power function.

2.6 BPA Actions Prior to Allocating Tier 2 Cost to a Tier 1 Cost Pool

If, for purposes of ensuring cost recovery, BPA determines that it must reallocate to any Tier 1 Cost Pool costs that would otherwise be allocated to any Tier 2 Cost Pool under the PRDM, to the extent practicable, BPA will reallocate such costs only after taking the following actions:

1) BPA will make reasonable efforts to recover the costs from the party(s) that would otherwise be responsible for such costs. Such efforts may include making demand on any available credit support and pursuing legal action when BPA determines it is appropriate.
2) BPA will make good faith efforts to reduce the costs that are proposed to be reallocated, so as to offset the cost that would otherwise occasion the need for a reallocation to ensure cost recovery.
3) Prior to a BPA proposal in a 7(i) Process to reallocate costs from a Tier 2 Cost Pool to the Composite Cost Pool, BPA will convene a public meeting with customers and interested parties to discuss the proposal and to elicit alternatives to reallocating the costs. If an alternative cost recovery mechanism appears to be viable, BPA

would propose such an alternative cost recovery mechanism in the next 7(i) Process.

These actions, or disputes over whether the Administrator has satisfied them, do not override and will not be allowed to frustrate the Administrator's responsibility to recover costs and timely repay the U.S. Treasury.

2.7 Slice True-Up

Slice customers will have an annual Slice True-Up Adjustment for expenses and revenue credits allocated to the Composite Cost Pool (see Table 2, Section A) and to the Slice Cost Pool (see Table 2, Section B). The annual Slice True-Up Adjustment will be calculated for each Fiscal Year as soon as BPA's audited actual financial data are available (usually in November). Actual expenses during a Fiscal Year to implement a request of and for the benefit of an individual Slice customer will be billed and paid in accordance with the contract governing the implementation of such request.

2.8 Composite Cost Pool True-Up Charge

The Composite Cost Pool True-Up Charge is applicable to the Slice Product. The Composite Cost Pool True-Up Charge can be either positive or negative and is calculated as the Composite Cost Pool Slice True-Up Billing Determinant multiplied by the Composite Cost Pool Slice True-Up Rate.

2.8.1 Composite Cost Pool Slice True-Up Billing Determinant

For each Slice customer, the annual Slice True-Up Billing Determinant for the Composite Cost Pool will be calculated as:

$$STUcomp_{BD} = Slice\% * \left(\sum CHWM - UnusedCHWM\right)$$

Where:

$STUcomp_{BD}$ = A Slice customer's Composite Cost Pool Slice True-Up billing determinant in kWh applicable to the Composite Cost Pool True-Up Rate in mills/kWh

Slice% = A customer's Slice percentage

$\sum CHWM$ = sum of customer CHWMs

UnusedCHWM = The actual Unused CHWM for a Fiscal Year as adjusted for actual loads effectively served at Tier 1 rates

2.8.2 Composite Cost Pool Slice True-Up Rate

The Composite Cost Pool Slice True-Up Rate is calculated by subtracting (i) the forecast annual expenses and revenue credits allocated to the Composite Cost Pool for the applicable Fiscal Years of the Rate Period from (ii) the actual expenses and revenue credits in the applicable Fiscal Year of the Rate Period that are allocable to the Composite Cost Pool. That difference will then be divided by the total amount of MWhs sold in the same Fiscal Year at PF Tier 1 rates, as adjusted by the Marginal Energy True-Up, to calculate the mills/kWh Slice True-Up Rate.

$$STUcomp_R = \frac{(CCP_{Actual} - CCP_{Forecast})}{(\sum CHWM - UnusedCHWM)}$$

Where:

$STUcomp_R$ = the Composite Cost Pool Slice True-Up in mills/kWh applicable to a Slice customer's kWh Composite Cost Pool Slice True-Up billing determinant

CCP_{Actual} = the actual expenses and revenue credits in the applicable Fiscal Year of the Rate Period that are allocable to the Composite Cost Pool

$CCP_{Forecast}$ = the forecast annual expenses and revenue credits allocated to the Composite Cost Pool for the applicable Fiscal Years of the Rate Period

$\sum CHWM$ = sum of customer CHWMs

$UnusedCHWM$ = The actual Unused CHWM for a Fiscal Year as adjusted for actual loads effectively served at Tier 1 rates

2.8.2.1 Treatment of Firm Surplus and Secondary Adjustment Line Item

As part of the Composite Cost Pool True-Up, the Firm Surplus and Secondary Credit (from Unused Contract High Water Mark (CHWM)) will be revised to reflect the actual effective Unused CHWM for each Fiscal Year and the resulting revenue difference between a sale at the posted Composite Customer Rate and at the 7(i) Process-determined value of Unused CHWM. The dollar amount calculated, which may be positive or negative, will be used to adjust the forecast Firm Surplus and Secondary Credit (from Unused Contract High Water Mark (CHWM)) line item to calculate the actual Firm Surplus and Secondary Credit (from Unused Contract High Water Mark (CHWM)) line item used in to calculate the Composite Cost Pool Slice True-Up Rate.

2.8.2.2 Treatment of Other Revenue Credit Line Items

As part of the Composite Cost Pool True-Up, some rate revenue credits, such as IP and NR revenue line items, may be subject to true-up as determined in each 7(i) Process. When a revenue credit line item is subject to true-up that varies because the actual amount of power sold is different than the forecast amount of power sold, the forecast revenue credit will be adjusted to account for the revenue difference assuming an increased or decreased market power sale – such as a kWh decrease in a NR power sale and an equal kWh increase in a market power sale, or vice versa. The revenue difference calculated, using the formula established in each 7(i) Process, which may be positive or negative, will be used to adjust the forecast revenue credit line items to calculate the actual revenue credit line items used in to calculate the Composite Cost Pool Slice True-Up Rate.

2.8.2.3 Minimum Required Net Revenue Line Items

The actual expenses and revenue credits allocable to the Composite Cost Pool will include a component for the amount in a Fiscal Year by which BPA's actual cash requirements exceed the total actual non-cash expenses in the Composite Cost Pool. This is called the Minimum Required Net Revenue (MRNR). When BPA's actual cash requirements do not exceed the total actual non-cash expenses in the Composite Cost Pool, MRNR will equal zero. Any revisions to this MRNR treatment will be proposed by BPA in a 7(i) Process.

2.8.3 Slice Cost Pool True-Up Charge

The annual Slice True-Up Adjustment Charge for the Slice Cost Pool will be calculated by 1) subtracting (i) the forecast annual expenses and revenue credits allocated to the Slice Cost Pool for the applicable Fiscal Years of the Rate Period from (ii) the actual expenses and revenue credits that are allocable to the Slice Cost Pool in the applicable Fiscal Year of the Rate Period and 2) multiplying the difference from 1 above by each customer's Slice Percentage pursuant to Exhibit K of the Slice Contract divided by the sum of all Slice Percentages for that Fiscal Year pursuant to Exhibit K of the Slice Contract. The dollar amount calculated, which may be positive or negative, constitutes the Slice True-Up Adjustment Charge for the Slice Cost Pool.

2.8.4 Treatment of New Costs and New Credits, and Costs and Revenues Not Subject to Slice True-Up

In the annual Slice True-Up Adjustment, BPA may make an interim allocation of New Expenses or New Credits for which categories do not exist on Table 2. If BPA makes such an interim allocation among the Cost Pools, it will do so based on the PRDM cost allocation principles (see Section 2.1). BPA will make a final decision on the allocation of New Expenses or New Credits among the Cost Pools in the next scheduled power rate 7(i) Process. If the cost allocation finally adopted in the 7(i) Process is different from the interim allocation implemented by BPA through the Slice True-Up Adjustment, the Slice customers will be compensated or charged based on their over-payment or under-payment, in either case with interest (at the rate specified in the Slice customer's CHWM Contract) from the first calendar day of the Fiscal Year in which the True-Up Adjustment Charge containing the interim allocation was calculated to the due date of the bills containing payment(s) or credit(s) related to the final allocation.

For forecast expenses or revenue credits allocated to either the Composite Cost Pool or the Slice Cost Pool that are not subject to the Slice True-Up, for purposes of all Slice True-Up Adjustment calculations the actual expenses and revenue credits allocable to such Cost Pools for each Fiscal Year will be deemed to be equal to the forecast of such expenses or revenue credits in the applicable 7(i) Process. The expenses and revenue credits that are not subject to true-up to actual expenses and revenue credits in the Slice True-Up Adjustment will be determined in each 7(i) Process.

2.8.5 Slice True-Up Charge

BPA will provide Slice customers a preliminary estimate of the Slice True-Up Charge before completion of BPA's financial audit for each Fiscal Year. The Slice True-Up Charge for each customer will be the sum of the Composite Cost Pool True-Up Charge and the Slice Cost Pool True-Up Charge calculated for each Slice customer. BPA will notify Slice customers of their Slice True-Up Charge that is calculated after audited actual financial data are available. The Slice True-Up Charge are included in customer bills in the month (or months) following notification.

The Composite Cost Pool True-Up Charge and the Slice Cost Pool True-Up will be added together if both are negative or both are positive, and will be netted against each other if one adjustment is positive (adjustment is a charge) and the other adjustment is negative (adjustment is a credit). The result of this summing or netting, as applicable, will be the final Slice True-Up Charge.

The final Slice True-Up Charge for each customer will be applied either as a one-month credit (if the adjustment is negative) or as a three-month charge (if the adjustment is positive) spread equally across the three months following the month the final Slice True-Up Charge is determined by BPA. Slice customers have the option to pay the entire charge in one month.

Interest will be computed and added to the Slice True-Up Charge for each Slice customer at the rate and for the period specified in the Slice customer's CHWM Contract.

Any adjustments to the billed Slice True-Up Charge will be determined by BPA upon the later to occur of 1) BPA's issuance of its written final resolutions of Slice True-Up Charge issues at conclusion of the Cost Verification Process or 2) BPA's issuance of a written decision by the Administrator that affirms or rejects (in whole or in part) the recommendation of the third-party expert, all as set forth in Attachment A.

2.8.6 Cost Verification Process for the Slice True-Up Charge

BPA will conduct a Cost Verification Process that will permit Slice customers and other customers to assess whether BPA has correctly calculated the amount of each expense or revenue credit subject to the Slice True-Up Charge, and whether the final Slice True-Up Charge contains only those expenses and revenue credits permitted to be included in—and does not contain any expenses or revenue credits excluded from—the Slice Rate pursuant to the PRDM. The Cost Verification Process will not enable customers to question or dispute BPA's accounting policies and standards, management decisions, or other policies. The Cost Verification Process for the Slice True-Up Charge will be conducted in accordance with Attachment A to this PRDM.

2.9 Cost Review Public Process

BPA will conduct, outside the PRDM, a Cost Review Public Process. This public process will include periodic meetings to allow customers and interested parties to review and obtain information from BPA, such as BPA's financial performance, comparison of BPA's actual costs to its forecast costs, and assignment of costs among cost categories and Cost Pools. For any issues raised in this Cost Review Public Process, BPA will determine if resolution is needed in a 7(i) Process.

Table 2-1
ALLOCATED TIERED COSTS
(These tables are placeholders to be updated by Initial Proposal.)

	Composite Cost Pool					
	Costs and Rate Adjustments	*Year 1*	*Actual*	*Year 2*	*Actual*	*Total Rate Perio*
1	**Operating Expenses**					
2	**Power System Generation Resources**					
3	**Operating Generation**					
4	COLUMBIA GENERATING STATION (WNP-2)					
5	BUREAU OF RECLAMATION					
6	CORPS OF ENGINEERS					
7	CRFM STUDIES					
8	LONG-TERM CONTRACT GENERATING PROJECTS					
9	**Sub-Total**					
10	**Operating Generation Settlement Payment and Other Payments**					
11	COLVILLE GENERATION SETTLEMENT					
12	SPOKANE LEGISLATION PAYMENT					
13	**Sub-Total**					
14	**Non-Operating Generation**					
15	TROJAN DECOMMISSIONING					
16	WNP-1&3 DECOMMISSIONING					
17	**Sub-Total**					
18	**Gross Contracted Power Purchases**					
19	PNCA HEADWATER BENEFITS					
20	OTHER POWER PURCHASES (Designated Obligations or Purchases)					
21	HEDGING/MITIGATION (NON-SLICE COST)	[redacted]				
22	OTHER POWER PURCHASES (NON-SLICE COST)					
23	**Sub-Total**					
24	**Bookout Adjustment to Power Purchases (omit)**					
25	**Augmentation Power Purchases (omit - calculated below)**					
26	AUGMENTATION POWER PURCHASES					
27	**Sub-Total**					
28	**Exchanges and Settlements**					
29	RESIDENTIAL EXCHANGE PROGRAM (REP)					
30	OTHER SETTLEMENTS					
31	**Sub-Total**					
32	**Renewable Generation**					
33	RENEWABLES (excludes KIII)					
34	**Sub-Total**					
35	**Generation Conservation**					
36	CONSERVATION ACQUISITION					
37	CONSERVATION INFRASCTRUCTURE					
38	LOW INCOME WEATHERIZATION & TRIBAL					
39	ENERGY EFFICIENCY DEVELOPMENT					
40	DISTRIBUTED ENERGY RESOURCES					
41	LEGACY					
42	MARKET TRANSFORMATION					
43	**Sub-Total**					
44	**Power System Generation Sub-Total**					

46	**Power Non-Generation Operations**
47	**Power Services System Operations**
48	EFFICIENCIES PROGRAM
49	INFORMATION TECHNOLOGY
50	GENERATION PROJECT COORDINATION
51	ASSET MGMT ENTERPRISE SVCS
52	SLICE IMPLEMENTATION (SLICE COST)
53	**Sub-Total**
54	**Power Services Scheduling**
55	OPERATIONS SCHEDULING
56	OPERATIONS PLANNING
57	**Sub-Total**
58	**Power Services Marketing and Business Support**
59	GRID MOD
60	EIM INTERNAL SUPPORT
61	POWER INTERNAL SUPPORT
62	COMMERCIAL ENTERPRISE SVCS
63	OPERATIONS ENTERPRISE SVCS
64	POWER R&D
65	SALES & SUPPORT
66	STRATEGY, FINANCE & RISK MGMT (REP support costs included here)
67	EXECUTIVE AND ADMINISTRATIVE SERVICES (REP support costs included here)
68	CONSERVATION SUPPORT
69	**Sub-Total**
70	**Power Non-Generation Operations Sub-Total**
71	**Power Services Transmission Acquisition and Ancillary Services**
72	TRANSMISSION and ANCILLARY Services - System Obligations
73	3RD PARTY GTA WHEELING
74	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)
75	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Non-Slice Cost)
76	TRANS ACQ GENERATION INTEGRATION
77	EESC CHARGES (Composite)
78	TELEMETERING/EQUIP REPLACEMT
79	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**
80	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**
81	**Fish & Wildlife**
82	**USF&W Lower Snake Hatcheries**
83	**Planning Council**
84	**Fish & Wildlife RDC Funds**
85	**Lower Snake Hatcheries RDC Funds**
86	**Fish and Wildlife/USF&W/Planning Council Sub-Total**
87	**BPA Internal Support**
88	**Additional Post-Retirement Contribution**
89	**Agency Services G&A (excludes direct project support)**
90	**BPA Internal Support Sub-Total**
91	**Bad Debt Expense (Composite Cost)**
92	**Bad Debt Expense (Non-Slice Cost)**
93	**Other Income, Expenses, Adjustments**
94	**Depreciation (Composite Cost)**
95	**Depreciation (Non-Slice Cost)**
96	**Amortization**
97	**Accretion (CGS)**
98	**Total Operating Expenses**
99	
100	**Other Expenses and (Income)**
101	Net Interest Expense
102	LDD
103	Irrigation Rate Discount Costs
104	Revenues, PRDM Rate Impact Credit, Mitigation (RIC-M)
105	Costs, PRDM Rate Impact Credit, Mitigation (RIC-M)
106	FPS (Surplus)/Shortfall
107	7(c)(2) Delta Allocation
108	7(b)(2) / 7(b)(3) Protection Amount
109	7(b)(2) Industrial Adjustment
110	**Sub-Total**
111	**Total Expenses**

113	**Revenue Credits**
114	Generation Inputs for Ancillary, Control Area, and Other Services Revenues
115	Downstream Benefits and Pumping Power revenues
116	4(h)(10)(c) credit
117	PRSC Net Credit (Composite)
118	Colville and Spokane Settlements
119	Energy Efficiency Revenues
120	PF Load Forecast Deviation Liquidated Damages
121	Miscellaneous revenues
122	Renewable Energy Certificates
123	Net Revenues from other Designated BPA System Obligations (Upper Baker)
124	RSS Revenues
125	Firm Surplus and Secondary Adjustment (from Unused RHWM)
126	Balancing Augmentation Adjustment
127	Transmission Loss Adjustment
128	Tier 2 Rate Adjustment
129	NR Revenues
130	**Total Revenue Credits**
131	
132	**Augmentation Costs (not subject to True-Up)**
133	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)
134	Augmentation Purchases
135	**Total Augmentation Costs**
136	
137	**DSI Revenue Credit**
138	Revenues 12 aMW @ IP rate
139	**Total DSI revenues**
140	
141	**Minimum Required Net Revenue Calculation**
142	Principal Payment of Fed Debt for Power
143	Repayment of Non-Federal Obligations (EN Line of Credit)
144	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls)
145	Irrigation assistance
146	**Sub-Total**
147	Depreciation
148	Amortization
149	Accretion
150	Capitalization Adjustment
151	Amortization of Refinancing Premiums/Discounts (MRNR - Reverse Sign)
152	Amortization of Cost of Issuance (MRNR-reverse sign)
153	Cash freed up by DSR refinancing
154	Gains/Losses on Extinguishment
155	Non-Cash Expenses
156	Prepay Revenue Credits
157	Non-Federal Interest (Prepay)
158	Contribution to decommissioning trust fund
159	Gains/losses on decommissioning trust fund
160	Interest earned on decommissioning trust fund
161	Revenue Financing Requirement
162	Capital Financing (RCD)
163	Other Adjustments
164	Payments for Litigation Stay Agreements
165	**Sub-Total**
166	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expenses
167	Minimum Required Net Revenues
168	
169	Total Composite Cost

	Slice Cost Pool					
	Costs and Rate Adjustments	Year 1	Actual	Year 2	Actual	Total Rate Perio
170	SLICE IMPLEMENTATION					
171	Total Slice Cost					

	Non-Slice Cost Pool					
	Costs and Rate Adjustments	Year 1	Actual	Year 2	Actual	Total Rate Perio
172	Other Power Purchases (Balancing)					
173	Other Power Purchases (Capacity)					
174	Hedging/Mitigation					
175	Transmission & Ancillary Services					
176	Third Party Trans & Ancillary Services					
177	Bad Debt Expense					
178	Depreciation					
179	Interest Earned on BPA Fund for Power					
180	Planned Net Revenues for Risk					
181	Accrual revenues (MRNR adjustment,if applicable)					
182	PRDM Rate Impact Credit, Capacity (RIC-C)					
183	Less Revenue Credits:					
184	Tier 1 Secondary Revenue Credit (less Secondary associated with Unused RHWM)					
185	Demand Revenue					
186	Peak Load Variance Revenue					
187	Marginal Energy True-Up Net Revenue					
188	Total Non-Slice Cost					

	Tier 2 Cost Pool (calculated for each T2 Rate)					
	Costs and Rate Adjustments	Year 1	Actual	Year 2	Actual	Total Rate Perio
189	Acquisition Costs					
190	BPA Overhead Costs					
191	RSS Adder					
192	Tier 2 Change Fee, Tier 2 Change Charge (Tier 2 Long-Term)					
193	Other costs, including risk-related, if appropriate					
194	Total Tier 2 Cost					

	Allocation Between Composite and Non-Slice Cost Pools					
	Costs Item	Year 1	Year 1	Year 12	Year 2	Total Rate Perio
195	Transmission & Ancillary Services					
196	Bad Debt Expense					
197	Depreciation					

3 RESOURCES AND AUGMENTATION

Chapter objectives: Describe and establish the federal resources that will be used in the calculation of the size of resources (existing and augmentation resources) to serve Tier 1 loads, for purpose of firm output, cost allocation, and Slice product, in the 7(i) rates process.

This chapter describes how BPA will identify the resources whose costs will be recovered through Tier 1 rates as established in each 7(i) Process. This chapter also identifies types of augmentation, and the cost allocation and rate treatment applicable to each type of augmentation. Lastly, this chapter specifies how BPA will track various types of resource acquisitions.

3.1 Tier 1 System Resources

In each 7(i) Process, BPA will update the list of resources that are considered Tier 1 System Resources for setting the Tier 1 rates and establishing the amount of firm power provided through the Slice product. Tier 1 System Resources are the resources listed in Table 3.1, as updated for any new resources, including market purchases, that BPA determines are needed to meet its CHWM obligations. The firm power of these resources will be determined in each 7(i) Process and is defined as the Tier 1 Firm System Output.

3.2 System Obligations

3.2.1 Designated System Obligations

Designated System Obligations, as listed in Table 3.2, are BPA obligations that: 1) are directly assigned to, or from, the generation output or capability of the Tier 1 System Resources, or 2) are incurred because of contracts, operational obligations, memorandums of agreement, treaties, statutes, regulations, court orders, or executive orders, as individual or in combination that create a firm obligation for the Tier 1 System Resources. Designated System Obligations also includes the portion of BPA's ancillary and control area service obligations that are provided from the Tier 1 System Resources. These obligations are considered firm obligations of the system regardless of weather, water, or economic conditions. These obligations may involve energy, capacity, or a combination of the two.

Designated System Obligations can vary from year to year and change over time. Any costs related to, or revenues recovered from, Designated System Obligations will be allocated to the Composite Cost Pool.

Designated System Obligations may continue where a successor contract replaces an expiring listed contract. The Designated System Obligations listed on Table 3.2 will not be removed for the duration of this PRDM. If there is a cessation of any such Designated System Obligation, the obligation amount will be set to zero when the obligation expires. Table 3.2 may be updated to include new Designated System Obligations.

3.2.2 New Designated System Obligations

BPA will, if practicable, hold a public process before entering into a new Designated System Obligation. Where holding such a process is not practicable before entering into or becoming subject to a new Designated System Obligation, BPA will hold such process before a new Designated System Obligation is added to Table 3.2 and will document any change in the next applicable 7(i) Process.

3.2.3 Large Designated System Obligation Increases

If BPA forecasts a 10 percent or greater increase in total Designated System Obligations over the most recently published forecast of Designated System Obligations, then BPA shall notify all customers with CHWM Contracts of such change as soon as practical. Upon written request of not less than 25 percent of the customers with CHWM Contracts (by number), BPA will hold a public process on the matter.

In such a public process, BPA will hold at least one open meeting to review BPA's forecast of the obligation amounts. BPA will consider written comments submitted in connection with such meeting(s). BPA will respond to reasonable requests to provide information that is non-confidential and is reasonably related to BPA's determination of new and existing Designated System Obligations and the forecast obligation amounts. Issues related to cost allocation, rate impacts, or rate treatment of changes to Designated System Obligations will not be addressed in such process, but rather in the appropriate 7(i) Process.

3.3 Augmentation

There are two types of augmentation used for purposes of this PRDM, CHWM Modeled Augmentation and Rate Period Augmentation.

3.3.1 CHWM Modeled Augmentation

CHWM Modeled Augmentation is not a forecast of physical resources needed for load-resource balance. CHWM Modeled Augmentation is a PRDM construct used to establish the simulated Slice capability and to equitably allocate costs between Slice and Non-Slice rates. CHWM Modeled Augmentation is greater than zero when the Tier 1 System Output reduced for Designated System Obligations is less than the sum of customer CHWMs.

$$CHWM\ Modeled\ Augmentation = Max(0\,, \sum CHWM_{all} + DSO - T1FSO)$$

where:

$T1FSO$ = Tier 1 Firm System Output

DSO = Designated System Obligations

$\sum CHWM_{all}$ = sum of CHWMs for all customers

CHWM Modeled Augmentation is an annual average modeled amount of power needed to meet the sum of customer CHWMs with the Tier 1 System Resources after meeting Designated System Obligations. Any Unused CHWM will be used to offset the CHWM Modeled Augmentation. That is, CHWM Modeled Augmentation offset by Unused CHWM will reduce the Unused CHWM amount debited from the Non-Slice Cost Pool and credited to the Composite Cost Pool. CHWM Augmentation will be included as an annual flat block of power for calculating the simulated Slice capability and the portion of a customer's Net Requirement met with the Slice product.

3.3.2 Rate Period Augmentation

Rate Period Augmentation is the forecast average annual amount of power needed to be in load and resource balance after considering all of BPA's resources (see tables 3.1, 3.3, 3.4, and 3.5 below) and obligations (*e.g.*, Designated System Obligations, power needed to serve loads under section 5 of the Northwest Power Act). The cost of Rate Period Augmentation will be based on the expected cost of a flat annual block of power determined in each 7(i) Process for the applicable Fiscal Year and allocated to the Composite Cost Pool. The forecast costs of augmentation may be subject to the Slice True-Up as determined in each 7(i) Process.

3.4 Balancing Power Purchases

In each 7(i) Process, BPA will forecast its Balancing Power Purchase costs. Balancing Power Purchases are distinct from Rate Period Augmentation in that they are power purchases or resource acquisitions forecast by BPA in a 7(i) Process to be made by BPA for periods within a year during which BPA's resource capability is insufficient to meet BPA's obligations for that period. Such Balancing Power Purchases will not be included when calculating Rate Period Augmentation. BPA's Balancing Power Purchase costs may include procured contract purchases as well as a forecast of future procurements. The cost of BPA's Balancing Power Purchases will be allocated to the Non-Slice Cost Pool. The Composite Cost Pool may include a debit with an equal and opposite credit to the Non-Slice Cost Pool to account for any Balancing Power Purchase costs associated with rates other than Tier 1 Non-Slice rates. For example, such a Composite to Non-Slice Cost Pool adjustment would be needed if NR-rate related Balancing Power Purchase costs are being allocated to the Non-Slice Cost Pool when NR rate revenue is allocated to the Composite Cost Pool. Any such adjustment would be established through the 7(i) Process.

3.5 Tier 1 Non-Slice Capacity Acquisitions

BPA may make capacity resource acquisitions for meeting its Tier 1 Non-Slice load obligations. To the extent BPA makes these type of resource acquisitions, it will list these resources in Table 3.3 as updated each 7(i) Process. The cost of Tier 1 Non-Slice Capacity Acquisitions will be allocated to the Non-Slice Cost Pool.

3.6 PF Tier 2 Acquisitions

BPA may make resource acquisitions (energy, capacity or a combination of both) for purposes of meeting its PF load obligations served at Tier 2 rates. To the extent BPA makes these type of resource acquisitions, it will list these resources in Table 3.4 with a note regarding the resource's originally purchased purpose, *e.g.,* to serve loads under a specific Tier 2 Rate Alternative. Table 3.4 will be updated each 7(i) Process. The cost of Tier 2 Acquisitions will be allocated to the applicable Tier 2 Cost Pool.

3.7 All Other Resource Acquisitions

BPA may make resource acquisitions (energy, capacity or a combination of both) for purposes other than to meet its PF load obligations served at Tier 1 and Tier 2 rates. All Other Resource Acquisitions will be listed in Table 3.5 with a note regarding the resource's originally purchased purpose, *e.g.,* to serve loads at NR rates. To the extent a resource is originally intended to be used for multiple purposes, the resources will be listed multiple times with each specific purpose and portion included. This may result in the same resource being listed in Table 3-1, Table 3-3, Table 3-4, and multiple times in Table 3-5. Consistent with the statutory functionalization and allocations depicted in Figure 2-1, any costs related to All Other Resource Acquisitions, or revenues recovered as a result of making All Other Resource Acquisitions, will be allocated to the Composite Cost Pool.

Table 3-1
TIER 1 SYSTEM RESOURCES

1	**Regulated Hydro Projects**	**Expiration**	**Portion of Resource**
2	Albeni Falls	n/a	100%
3	Bonneville	n/a	…
4	Chief Joseph	n/a	
5	Dworshak	n/a	
6	Grand Coulee	n/a	
7	Hungry Horse	n/a	
8	Ice Harbor	n/a	
9	John Day	n/a	
10	Libby	n/a	
11	Little Goose	n/a	
12	Lower Granite	n/a	
13	Lower Monumental	n/a	
14	McNary	n/a	
15	The Dalles	n/a	
16	**Independent Hydro Projects**	**Expiration**	
17	Anderson Ranch	n/a	
18	Big Cliff	n/a	
19	Black Canyon	n/a	
20	Boise River Diversion	n/a	
21	Chandler	n/a	

22	Cougar	n/a	
23	Cowlitz Falls	6/30/2032	
24	Detroit	n/a	
25	Dexter	n/a	
26	Foster	n/a	
27	Green Peter	n/a	
28	Green Springs – USBR	n/a	
29	Hills Creek	n/a	
~~30~~	~~Idaho Falls (Upper, City, and Lower Plants)~~	~~9/30/2011~~	
31	Lookout Point	n/a	
32	Lost Creek	n/a	
33	Minidoka	n/a	
34	Palisades	n/a	
35	Roza	n/a	
36	**Other Projects**	**Expiration**	
37	Columbia Generating Station	n/a	
38	Dworshak/Clearwater Small Hydropower	n/a	
39	Fourmile Hill Geothermal	(year to year)	
40	Stateline Wind Project (30% share)	12/31/2026	
41	**Contract Purchases**	**Expiration**	
42	Priest Rapids CER for Canada	Treaty Entitlement Return	
43	Rock Island #1 CER for Canada	Treaty Entitlement Return	
44	Rock Island #2 CER for Canada	Treaty Entitlement Return	
45	Rock Reach CER for Canada	Treaty Entitlement Return	
46	Wanapum CER for Canada	Treaty Entitlement Return	

Table 3-2
DESIGNATED SYSTEM OBLIGATIONS

1	Obligation	Contract Number	Expiration Date	Discretionary Contract?
2	BPA to BRCJ	14-03-49151	8/23/2024	
3	BPA to BRCJ	14-03-17506	12/31/2023	
4	BPA to BRCR	14-03-73152	Mutually agreed	
5	BPA to BREG	14-03-49151	8/23/2024	
6	BPA to BRGC	14-03-001-12160	6/30/2017	
7	BPA to BROP	14-03-79239	Mutually agreed	
8	BPA to BRSI	14-03-49151	8/23/2024	
9	BPA to BRSID	14-03-99106	Mutually agreed	
10	BPA to BRSV	14-03-63656	Mutually agreed	
11	BPA to BRTD	14-03-32210	Mutually agreed	
12	BPA to BRTV	14-03-49151	8/23/2024	
13	BPA to BRYK	00PB-12132	9/30/2011 (year to year)	
14	BPA to BCHA Canadian Entitlement	99EO-40003	9/15/2024 (contract expected to be replaced)	
15	BPA to SPP Harney Wells	88BP-92436	2/25/2018 (contract expected to be replaced)	
16	Federal System Intertie Transmission Losses	n/a	(year to year)	
17	WRAP Capacity	n/a	Ongoing	Yes
18	Non-Power Uses Agreement	n/a	(year to year)	
19	Summer Storage Agreement	n/a	(year to year)	
20	Arrow Local	n/a	(year to year)	
21	Upper Baker	05PB-11542	(year to year)	
22	AOP's/Entity Agreements	n/a	(year to year)	
23	DOP's/Entity Agreements	n/a	(year to year)	
24	Power/Transmission Services MOA for generation inputs for ancillary, control, and other services	07PB-11856	9/30/2009 (contract expected to be replaced)	
25	Federal system transmission losses for power deliveries	n/a	(year to year)	
26	Interchange	n/a	(year to year)	
27	Loop flow support	n/a	(year to year)	
28	Voltage support (VAR)	n/a	(year to year)	
29	Project use loads not included in USBR	n/a	(year to year)	
30	Resource Support Services	n/a	(year to year)	
31	Other reserve obligation	n/a	(year to year)	

Table 3-3
TIER 1 NON-SLICE CAPACITY ACQUISITIONS

1	Resource	Contract #	Expiration	Portion of Resource
2	To be determined		n/a	100%
3			n/a	…
4			n/a	

Table 3-4
PF TIER 2 ACQUISITIONS

1	Resource	Contract #	Expiration	Purpose	Portion of Resource
2	To be determined		n/a		100%
3			n/a		…
4			n/a		

Table 3-5
ALL OTHER RESOURCE ACQUISITIONS

1	Resource	Contract #	Expiration	Purpose	Portion of Resource
2	To be determined		n/a		100%
3			n/a		…
4			n/a		

4 TIER 1 RATE DESIGN

Chapter objectives: This chapter is largely a re-write relative to TRM. These changes are driven by the overall Core design changes developed in the PRDM Public Process in 2024—with a few key changes: 1) a change in rate units and charge approach away from TOCA toward $/MWh (mills/kWh) based charges; 2) clarified price signals through the application of an Energy, Demand, and Peak Load Variance Charges; 3) increased price signal for capacity through a larger demand billing determinant that sends price signals for LF, BL—and which un-restricts it from HLH to all hours in a month; and 4) the introduction of capacity and mitigation credits outside the Core-charge billing determinants and the removal of the CDQ construct. The Super Peak Credit is retained as a more flexible and adaptable "Capacity Credit".

The Tier 1 rate design described in this chapter consists of three core elements: Energy Charges, Demand Charges, and Peak Load Variance Charges.

The rate design also includes two Rate Impact Credits: the RICc and the RICm. The RICc ensures forecast BP-29 Rate Period capacity needs are charged the embedded cost of capacity. The RICm helps transition customers from the Tiered Rate Methodology (TRM) to the PRDM by tempering rate impacts.

4.1 Tier 1 Energy Charges

The Tier 1 Energy Charges are calculated by multiplying Tier 1 energy rates (mills/kWh) by the quantity of Tier 1 energy (kWh) associated with the applicable PF product. The number of energy rates, and thereby energy charges, applicable during a Rate Period will be determined in each 7(i) Process; the PRDM does not dictate that a particular number of energy charges be implemented.

The energy charges will recover costs and credits allocated to the Composite, Non-Slice, and Slice Cost Pools. The Tier 1 energy charges that recover costs allocated to the Composite

Cost Pool apply to the Slice, Load Following, and Block products. The Tier 1 energy charges that recover costs and credits allocated to the Non-Slice Cost Pool apply to Load Following and Block products. The Tier 1 energy charges that recover costs and credits allocated to the Slice Cost Pool apply to the Slice product.

4.1.1 Tier 1 Energy Charge Billing Determinants

The quantity of Tier 1 energy that forms the basis for the Energy Charge Billing Determinant is defined as follows:

- A customer's Actual Hourly Tier 1 Load will be used to calculate the Tier 1 Energy Charge Billing Determinants applicable to Load Following and Block products—including the portion of Block that is purchased with the Slice product.
- A customer's Firm Slice Amount will be used to calculate the Tier 1 Energy Charge Billing Determinants applicable to the Slice product.

4.1.2 Composite Tier 1 Energy Rates

BPA will establish Composite Tier 1 Energy Rates in each 7(i) Process. The Composite Tier 1 Energy Rates are applicable to the Load Following, Block and Slice products (mills/kWh). The Composite Tier 1 Energy Rates will be calculated to recover costs and credits allocated to the Composite Cost Pool and will be shaped across the year, using a fixed scalar (mills/kWh) and expected market-based prices as determined in each 7(i) Process. The Composite Tier 1 Energy Rates can be positive or negative values.

BPA will use a Monthly/Diurnal market-based price to shape its energy rates (*i.e.,* one HLH and one LLH for each of the 12 months for a total of 24 market-based prices each year) unless BPA develops a different market-based price approach in a 7(i) Process (for example, more or less granular).

Prior to shaping, the average annual equivalent of the Composite Tier 1 Energy Rate is equal to:

$$CompositeTier1Rate_{ave} = \frac{CompositeCosts}{\Sigma ForecastTier1EBD_{all}}$$

where:

$CompositeTier1Rate_{ave}$ = the average annual equivalent of the Composite Tier 1 Energy Rates, expressed in mills/kWh, before being shaped, using a fixed scalar, to the market-based price as established in each 7(i) Process

CompositeCosts = total costs and credits in the Composite Cost Pool

$\Sigma ForecastTier1EBD_{all}$= forecast Tier 1 Energy Billing Determinants for Load Following, Block, and Slice products in kWh

4.1.3 Non-Slice Tier 1 Energy Rate

BPA will establish a Non-Slice Tier 1 Energy Rate in each 7(i) Process. The Non-Slice Tier 1 Energy Rate is a rate applicable to the Load Following and Block products (mills/kWh). The Non-Slice Tier 1 Energy Rate will be calculated to recover costs and credits allocated to the Non-Slice Cost Pool and will be a single annual rate. The Non-Slice Tier 1 Energy Rate can be a positive or negative value.

$$NonSliceTier1Rate = \frac{NonSliceCosts}{\Sigma ForecastTier1EBD_{NS}}$$

where:

NonSliceTier1Rate = Non-Slice Tier 1 Energy Rate expressed in mills/kWh

NonSliceCosts = total costs and credits in the Non-Slice Cost Pool

$ForecastTier1EBD_{NS}$= forecast Tier 1 Energy Billing Determinants for Load Following and Block products in kWh

4.1.4 Slice Tier 1 Energy Rate

BPA will establish a Slice Tier 1 Energy Rate in each 7(i) Process. The Slice Tier 1 Energy Rate is applicable to the Slice product (mills/kWh). The Slice Tier 1 Energy Rate will be calculated to recover costs and credits allocated to the Slice Cost Pool and will be a single rate annual rate. The Slice Tier 1 Energy Rate can be a positive or negative value.

$$SliceTier1Rate = \frac{SliceCosts}{\Sigma ForecastTier1EBD_{S}}$$

where:

SliceTier1Rate = Slice Tier 1 Energy Rate expressed in mills/kWh

SliceCosts = total costs and credits in the Slice Cost Pool

$ForecastTier1EBD_S$= forecast Tier 1 Energy Billing Determinants for the Slice product in kWh

4.2 Marginal Energy True-Up

At the end of each Fiscal Year, BPA will calculate a Marginal Energy True-Up. The Marginal Energy True-Up will be applicable to the Load Following, Block and Slice products. The Marginal Energy True-Up could be either a credit or a charge depending on actual energy use, CHWM amounts, and the directional difference between Tier 1 Rates and market prices. The purpose of the Marginal Energy True-Up is to: 1) provide customers full access to their CHWM; 2) ensure that a market-based energy rate is applied to energy use in excess of a customer's CHWM; 3) incent accurate load forecasts; and 4) appropriately account for directional differences between PF and Market. When the Marginal Energy True-Up is a credit, the credit will be reduced by 2 percent. When the Marginal Energy True-Up is a charge, the charge will be increased by 2 percent.

4.2.1 Marginal Energy True-Up Billing Determinant for the Load Following Product

The Marginal Energy True-Up Billing Determinant for the Load Following product is calculated using the following equations:

Condition 1: If a Load Following customer has Above-CHWM Load and the annual sum of a customer's Actual Hourly Tier 1 Load is less than its CHWM, then the Marginal Energy True-Up billing determinant is equal to:

$$METU_{BD} = Minimum(ACHWM, CHWM - \Sigma AHT1L_{Annual}) \times -1$$

where:

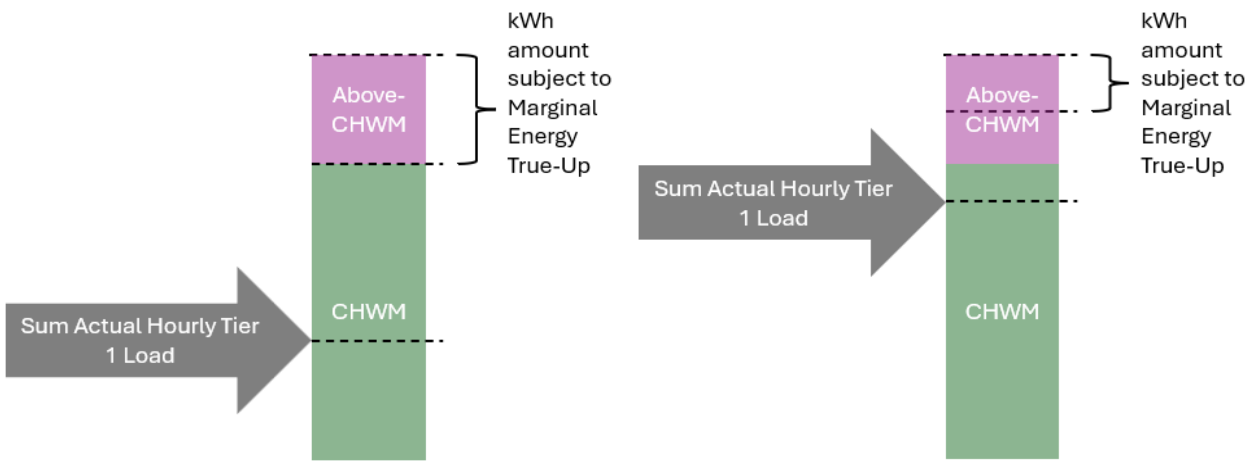
$METU_{BD}$= Marginal Energy True Up Billing Determinant in kWh

$ACHWM$ = the customer's Above Contract High Water Mark Load in annual kWh

$CHWM$ = the customer's Contract High Water Mark Load in annual kWh

$\Sigma AHT1L_{Annual}$= the customer's annual sum of Actual Hourly Tier 1 Load in kWh

Figure 4-1
Load Following Condition 1 Examples



Condition 2: If a Load Following customer's annual sum of a customer's Actual Hourly Tier 1 Load is greater than its CHWM, then the Marginal Energy True-Up billing determinant is equal to:

$$METU_{BD} = \Sigma AHT1L_{Annual} - CHWM$$

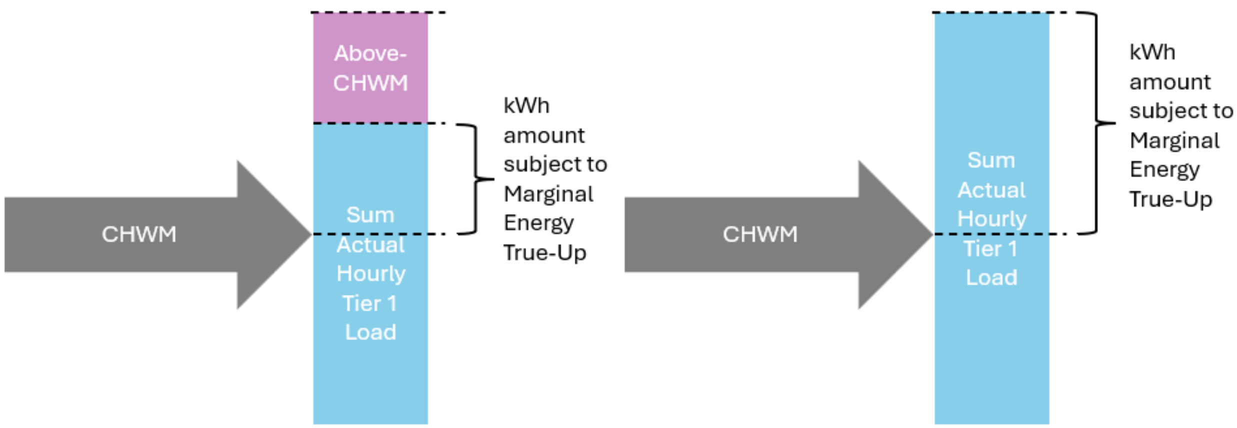
where:

$METU_{BD}$= Marginal Energy True Up Billing Determinant in kWh

$\Sigma AHT1L_{Annual}$= the customer's annual sum of Actual Hourly Tier 1 Load in kWh

$CHWM$ = the customer's Contract High Water Mark Load in annual kWh

Figure 4-2
Load Following Condition 2 Examples



If neither Condition 1 nor Condition 2 apply, then the Load Following customer's Marginal Energy True-Up billing determinant is zero.

4.2.2 Marginal Energy True-Up Billing Determinant for the Block and Slice Products

The Marginal Energy True-Up for the Block and Slice products is calculated using the following equations:

Condition 1: If a Block or Slice customer has no Above-RHWM Load and an Actual Annual Net Load that is greater than its Forecast Tier 1 Annual Net Load, then the Marginal Energy True-Up billing determinant is equal to:

$$METU_{BD} = Minimum(AANL - FANL, CHWM - FANL) \times -1$$

where:

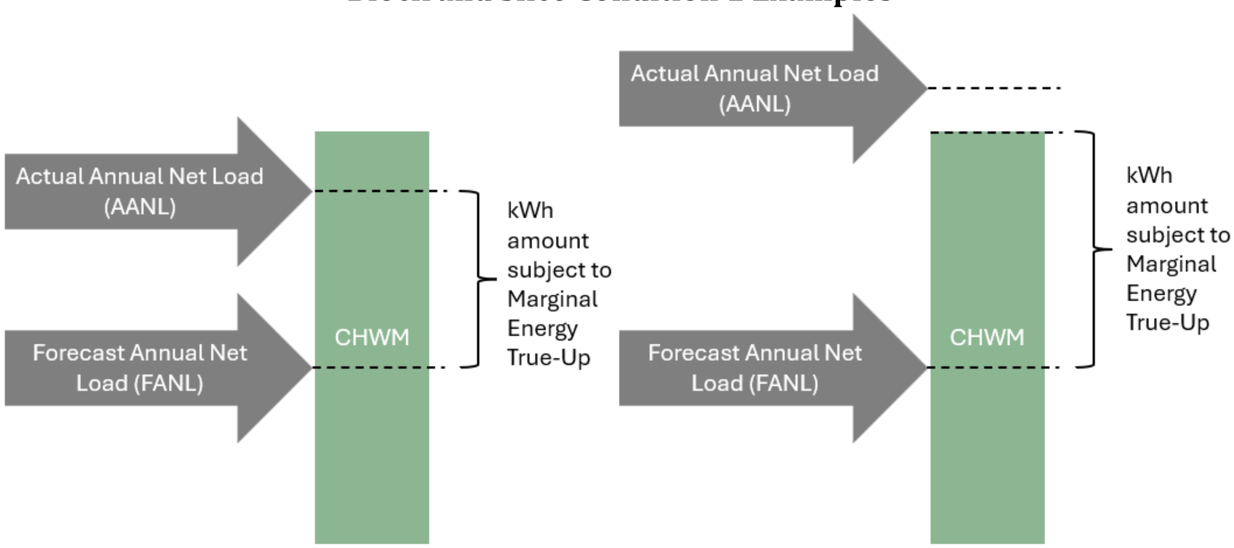
$METU_{BD}$ = Marginal Energy True Up Billing Determinant in kWh

$AANL$ = the customer's Actual Annual Net Load in annual kWh

$FANL$ = the customer's Forecast Annual Net Load in annual kWh

$CHWM$ = the customer's Contract High Water Mark Load in annual kWh

Figure 4-3
Block and Slice Condition 1 Examples



Condition 2: If a Block or Slice customer has no Above-CHWM Load and an Actual Annual Net Load that is less than its Forecast Annual Net Load, then the Marginal Energy True-Up billing determinant is equal to:

$$METU_{BD} = FANL - AANL$$

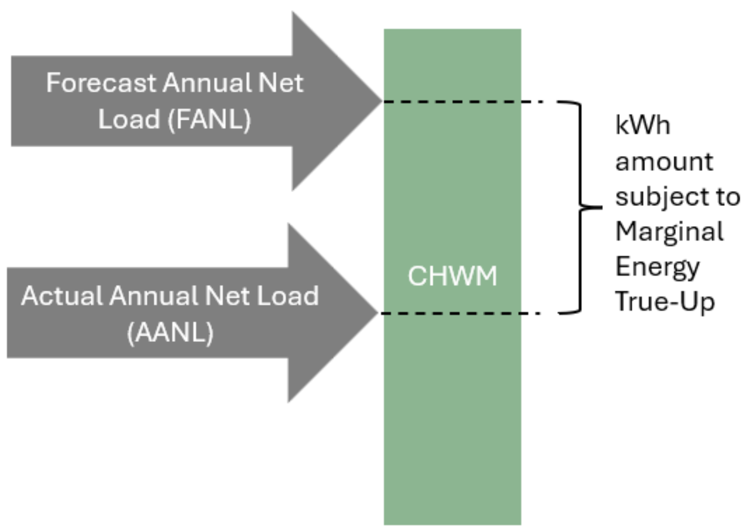
where:

$METU_{BD}$ = Marginal Energy True Up Billing Determinant in kWh

$FANL$ = the customer's Forecast Annual Net Load in annual kWh

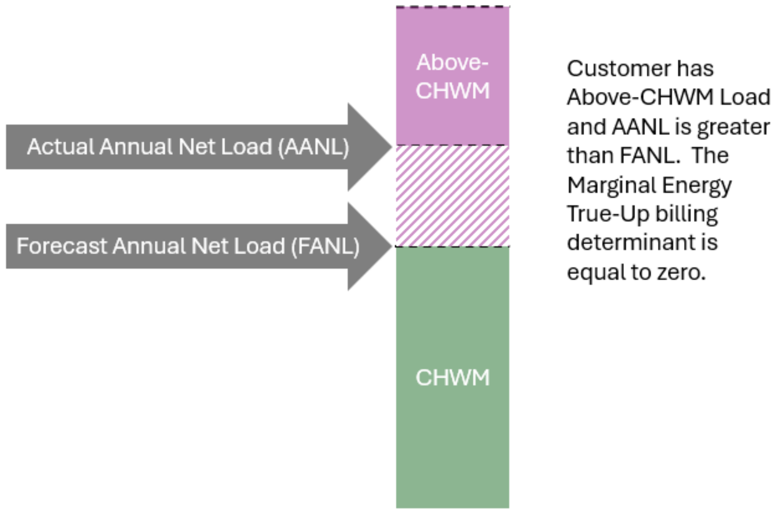
$AANL$ = the customer's Actual Annual Net Load in annual kWh

Figure 4-4
Block and Slice Condition 2 Example



Condition 3: If a Block or Slice customer has Above-RHWM Load and an Actual Annual Net Load that is greater than or equal to its Forecast Annual Net Load, then the Marginal Energy True-Up billing determinant is equal to zero.

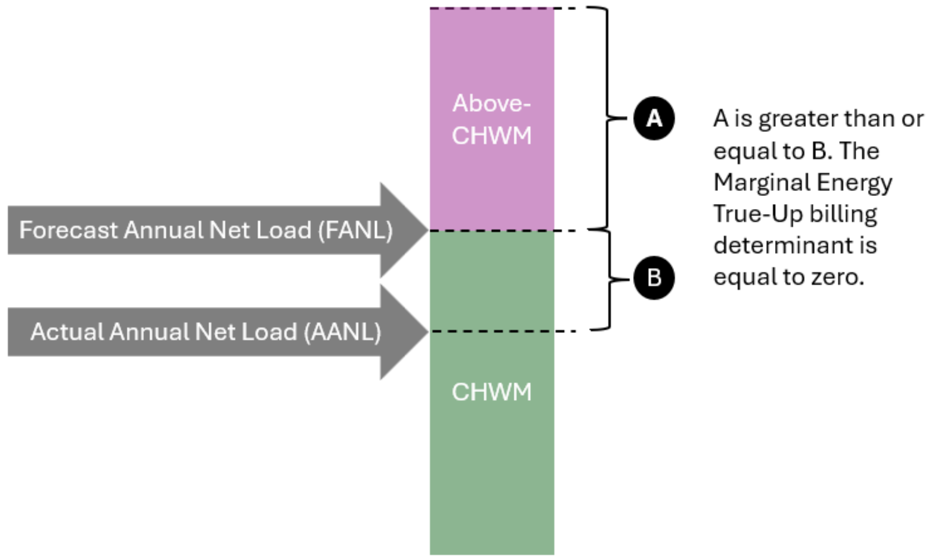
Figure 4-5
Block and Slice Condition 3 Example



Condition 4: If a Block or Slice customer has Above-CHWM Load and an Actual Annual Net Load that is less than its Forecast Annual Net Load, then two checks will be evaluated to determine the Marginal Energy True-Up billing determinant.

Condition 4 Check 1: If the Block or Slice customer's Above-CHWM Load is greater than or equal to its Forecast Annual Net Load minus its Actual Annual Net Load, then the Marginal Energy True-Up billing determinant is equal to zero.

Figure 4-6
Block and Slice Condition 4 Check 1 Example



Condition 4 Check 2: If the Block or Slice customer's Above-CHWM Load is less than its FANR minus its AANR, then the Marginal Energy True-Up billing determinant is equal to:

$$METU_{BD} = FANL - AANL - ACHWM$$

where:

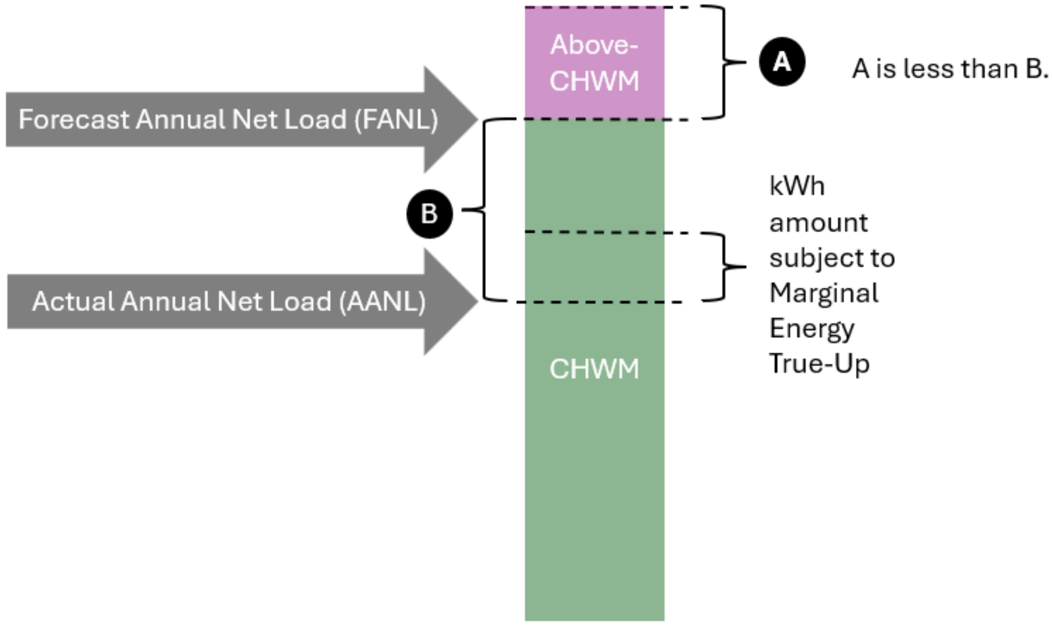
$METU_{BD}$ = Marginal Energy True Up Billing Determinant in kWh

$FANL$ = the customer's Forecast Annual Net Load in annual kWh

$AANL$ = the customer's Actual Annual Net Load in annual kWh

$ACHWM$ = the customer's Above Contract High Water Mark Load in annual kWh

Figure 4-7
Block and Slice Condition 4 Check 2 Example



4.2.3 Marginal Energy True-Up Rate

The Marginal Energy True-Up Rate is the mills/kWh difference between power purchased from BPA at its Tier 1 energy rates applicable to the Non-Slice product and the same amount of power had it been purchased at a market-based cost. The Marginal Energy True-Up Rate can be negative or positive, and is a single rate that is equal to the fixed scalar used to shape the Composite Tier 1 Energy Rates plus the Non-Slice Tier 1 Energy Rate as potentially calibrated (*i.e.*, adjusted up or down) to the Short-Term Tier 2 Rate, or another market-based price as established in each 7(i) Process.

4.3 Demand Charge

There are 12 Demand Charges—one for each month of the year—that are designed to send a marginal price signal to customers to both recover the cost of holding capacity to serve customer loads and encourage the efficient use of capacity. Forecast revenue received from the Demand Charges are credited to the Non-Slice Cost Pool. These Demand Charges are applicable to the Load Following and Block products. The Demand Charge is calculated as the Demand Charge Billing Determinant multiplied by the Demand Rate.

4.3.1 Demand Charge Billing Determinant

BPA will use two quantities to calculate a customer's monthly Demand Charge Billing Determinant: the customer's monthly Tier 1 Customer System Peak, and the customer's monthly average Actual Hourly Tier 1 Load. The following formula will be used to calculate a customer's monthly Demand Charge Billing Determinant:

$$DemandBD_{Mo} = CSP_{Tier1,Mo} - AHT1L_{ave,Mo}$$

where:

$DemandBD_{Mo}$= Demand Billing Determinant expressed in kW per month (kW/Mo)

$CSP_{Tier1,Mo}$= Tier 1 Customer System Peak each month

$AHT1L_{ave,Mo}$ = customer's average Actual Hourly Tier 1 Load each month expressed in akW

For a Joint Operating Entity (JOE), the calculation of the Demand Charge Billing Determinant will be based on each individual utility member. [BPA staff note that PNGC disagrees with this draft treatment.]

4.3.2 Tier 1 Customer System Peak

A customer's Tier 1Customer System Peak is equal to the customer's maximum Actual Hourly Tier 1 Load for each month.

4.3.3 Average Actual Hourly Tier 1 Load

The average Actual Hourly Tier 1 Load is calculated as the sum of the customer's Actual Hourly Tier 1 Load each month, expressed in kilowatt hours, divided by the total amount of hours in the same month.

4.3.4 Demand Rate

The Demand Rate will be based on the annual fixed costs (*e.g.*, capital, fixed fuel, and fixed operations and maintenance (O&M)) of the Marginal Capacity Resource, as adjusted for potential multiple uses of that capacity, as determined in each 7(i) Process. The Marginal Capacity Resource may be based on BPA's Resource Program, BPA's actual acquisitions, or third-party sources. Third-party sources may include, but are not limited to, the Energy Information Administration, EPRI Technical Assessment Guide, the Northwest Power and Conservation Council, and Integrated Resource Plans of Pacific Northwest electric utilities.

The annual fixed costs of the Marginal Capacity Resource, as potentially adjusted downward to account for multiple uses (for example, a battery used for shaping energy and voltage support), will be used to calculate an annual Demand Rate and will be shaped across the 12 months to create 12 monthly Demand Rates. The shape of the monthly Demand Rates will be established using monthly market-based prices, such as BPA's market energy price forecast or the monthly cost of capacity if a viable capacity market, or other mechanism valuing seasonable capacity, develops in the Pacific Northwest, as established in each 7(i) Process.

4.3.5 Demand Rate Adjustment Cap

Increases to the monthly Demand Rates will be limited to 5% every two years, with the exception of the Demand Rates set for the BP-29 Rate Period when the first Demand Rates under PRDM are established.

4.3.6 Capacity Credit

A customer can qualify for a Capacity Credit by contractually committing to provide BPA access to capacity not otherwise committed to the customer's load which, as determined solely by BPA, either: 1) reduces the Administrator's capacity obligations, or 2) can be used by BPA to help meet the Administrator's capacity obligations.

The amount of the Capacity Credit will be established in each 7(i) Process and will be tailored to the characteristics of the capacity provided. The Capacity Credit will be based on the marginal cost of capacity, such as the Marginal Capacity Resource as used to establish the Demand Rates described in this chapter, and potentially discounted to the specific characteristics of each source of capacity to account for any potential limits in availability like frequency and duration of use. The Capacity Credit may account for other operational characteristics of the capacity that add or subtract value, such as, but not limited to, accounting for any applicable energy value and recharge costs. The Capacity Credit will also be constructed with consideration of the potential impact on the customer's Tier 1 System Peak to limit situations where BPA would pay the customer twice for the same capacity—once through the Capacity Credit and again through a reduction in Demand Charge revenue—while also considering implementation ease and practicality.

4.4 Peak Load Variance Charge

The Peak Load Variance Charge(s) (PLVC), are applicable to the Load Following product and to eligible Block product customers who elect the Peak Load Variance Service (PLVS). The PLVC recovers the cost of holding capacity for load excursions outside BPA's expected peak load forecast. The costs recovered through the PLVC will be established using BPA's embedded cost of Supplemental Operating Reserves, or its successor. PLVC for the Load Following product will: 1) reflect applicable load diversity benefits, 2) be evaluated using a monthly embedded cost of a shared pool of capacity, and 3) only apply in months where BPA establishes a capacity planning standard applicable to its PF Public load obligations as determined in each 7(i) Process.

The billing determinants and rates used to calculate the PLVC will be established in each 7(i) Process and may be different as between the Load Following product and the Block product if planning, access to and use of PLVS capacity is determined to be materially different across the products. For example, if the Block product can be used in a way that decreases load diversity and shared pool benefits or if the Block product has access to PLVS capacity in months other than those where BPA establishes a capacity planning standard applicable to its PF Public load obligations. Revenue from the PLVC will be credited to the Non-Slice Cost Pool.

Energy provided through PLVS for the Load Following product will be included in Actual Hourly Tier 1 Load, and will be subject to all other applicable Tier 1 rates. Energy provided through PLVS for the Block product will be priced at a market-based energy rate as established in each 7(i) Process and will apply to any additional monthly energy taken through the PLVS above the customer's contractually defined Block amount. Energy provided through PLVS for the Block product within its contractually defined Block amount will be treated as Block load served at Tier 1 Rates.

4.5 Tier 1 Credits

The rate design includes two Rate Impact Credits: the RICc and the RICm. The RICc ensures forecast BP-29 capacity needs are charged the embedded cost of capacity. The RICm is a rate design mitigation tool used for transitioning customers from rates in the Tiered Rate Methodology (TRM) to rates in the PRDM, by tempering rate impacts over time.

For a Joint Operating Entity (JOE), the calculation and application of the RICc and RICm will be by individual utility member. [BPA staff note that PNGC disagrees with this draft treatment.]

4.5.1 Rate Impact Credit, Capacity (RICc)

The Rate Impact Credit for Capacity (RICc) credits the customer's energy rate for the cost difference between the marginal Demand Rate and BPA's embedded cost of capacity applied to the customer's forecast BP-29 Rate Period capacity needs. RICc is calculated for all customers regardless of BP-29 Rate Period product choice but will only be applied to the Load Following and Block Only products. RICc is calculated using the effective rate difference resulting from an application of the marginal demand rate and BPA's embedded cost of capacity. The cost of the RICc will result in a reduction in the demand revenue credited to the Non-Slice Cost Pool.

The RICc for each Load Following customer is equal to the difference between (1) the annual Tier 1 effective rate using BP-29 Rate Period forecast billing determinants applied to marginal Demand Rates and (2) the same BP-29 Rate Period forecast billing determinants applied to an embedded cost of capacity rate (mills/kWh). The embedded cost of capacity rate is calculated using the embedded cost of Supplemental Operating Reserves, or its successor, as established for the BP-29 Rate Period, adjusted to reflect the Tier 1 System Resources only, and shaped into months using each Rate Period's monthly Demand Rates.

The RICc for Block and Slice product customers is calculated the same as a Load Following customer, with the added assumption that each Block and Slice product customer elected to take only the Block product with a shaping capacity equal to the greater of: 1) the customer's BP-29 Rate Period contractual shaping amount, and 2) the maximum amount of shaping capacity the customer could have taken during the BP-29 Rate Period without being subject to a Peak Net Requirement check.

The formula applied to all products is as follows:

$$RIC_c = \frac{\sum_{i=1}^{12}(DemandRate_i - ECC_i)\ x\ DemandBD_i}{T1Energy_{RICc}}$$

where:

RICc = is a customer's Rate Impact Credit for Capacity expressed in mills/kWh

i = a month of the year

$DemandRate_i$ = is the monthly Demand Rate applicable to each Rate Period expressed in mills/kW defined in section 4.3.4 above.

ECC_i= is the embedded monthly cost of capacity calculated for the BP 29 Rate Period and shaped to the monthly Demand Rates applicable to each Rate Period expressed in mills/kW

$DemandBD_i$ = is the customer's monthly BP-29 Rate Period forecast Tier 1 Demand Billing Determinants for a Load Following customer or, for a Block and Slice customer, the greater of 1) the customer's BP-29 Rate Period contractual shaping amount and 2) the maximum amount of shaping capacity the customer could have taken during the BP-29 Rate Period without being subject to a Peak Net Requirement check

$T1Energy_{RICc}$= is the customer's sum of BP-29 Rate Period forecast Tier 1 energy

4.5.1.1 Recalculation of RICc

The RICc will be recalculated in each 7(i) Process based solely on changes to the Demand Rates as prescribed in Section 4.3.4. above.

4.5.1.2 Calculation of RICc for New Publics

When a New Public is formed entirely from another Existing Public customer with a RICc, the New Public's RICc will be set equal to the Existing Public's RICc. When a New Public is formed entirely from a combination of Existing Public customers, a Tier 1 Load weighted RICc will be calculated for the New Public. Under either scenario, the Existing Public customer's RICc will remain unchanged.

When a New Public is formed entirely from an entity other than an Existing Public, a RICc will be established for the New Public, and will be calculated as described above in Section 4.5.1, except the underlying load forecast will be that associated with the first Rate Period in which the New Public is eligible to purchase power at BPA's Tier 1 Rates. When a New Public is formed in part by an entity other than an Existing Public and in part by Existing Public(s), BPA may, in its sole discretion, use a weighted average RICc methodology that takes into consideration the multiple sources of all the Tier 1 Load, or BPA may choose to calculate the RICc assuming the New Public was formed entirely from an entity other than an Existing Public.

4.5.1.3 Calculation of RICc for Existing-to-Existing Public Annexation

A customer's RICc will not be recalculated for the Existing Public that is having its Tier 1 Load reduced due to annexation. The Existing Public gaining Tier 1 Load as a result of the annexation will have its RICc recalculated based on the weighted average of (1) its prior-to-annexation Tier 1 Load and associated RICc, and (2) the annexed Tier 1 Load and the RICc associated with that load.

4.5.1.4 Product Switching and RICc

A RICc will not be recalculated because of a product switch.

4.5.2 Rate Impact Credit, Mitigation (RICm)

The Rate Impact Credit for Mitigation (RICm) phases in rate impacts attributed to rate design changes between the previous and current Tier 1 Core rate design charges (Tiered Rate Design (TRM) to 2029 Public Rate Design Methodology). The Core charges under the TRM include the Customer Charges, the Load Shaping Charges, and the Demand Charges. The Core charges under the PRDM include the Energy Charges, the Demand Charges, and the Peak Load Variance Charge. The RICm will not measure any other potential sources of rate impacts, such as differences in the allocation of costs and credits, changes in the calculation of the Irrigation Rate Discount and changes in the Low-Density Discount.

The RICm is a rate credit that can be either positive or negative and is specific to each customer (mills/kWh). The RICm sets a positive-cap, or ceiling, for forecast rate impacts caused solely by the Core rate design, at the outset of the 2029 PRDM. The cost of that rate impact cap is allocated to the customers with forecast negative rate impacts based on an effective negative-cap, or floor, for rate impacts at the outset of the 2029 PRDM. The negative-cap, or floor, is solved for by increasing the floor for all customers until the sum of the RICm charges (*i.e.*, negative credits) is equal to some of the RICc credits. The BP-29 rate impact positive-cap will be 2 percent. The RICm will be phased out each year after FY 2029 by adding 0.10 mills/kWh to each customer's negative RICm until the customer's RICm is zero or above. When a customer's RICm flips from being negative to positive, that customer's RICm will be deemed fully phased out and be set to zero. A positive RICm will decline in direct proportion to the phase out of the aggregate cost of the RICm program. A phase out of the customer's positive or negative RICm will be in proportion to each other.

The phase out schedule applicable to customers with positive RICm Rates will be set in the BP-29 7(i) Process and fixed for the term of the contract. As forecasts change through time, there will be differences in the aggregate RICm credits and RICm charges. Any such difference, positive or negative, will be allocated to the Composite Cost Pool.

4.5.2.1 Calculation of RICm for New Publics

A RICm will not be established for any New Public. Under no situation will an Existing Public customer's RICm be changed as a result of the formation of a New Public.

4.5.2.2 Calculation of RICm for Existing-to-Existing Public Annexation

A customer's RICm will not be recalculated for the Existing Public that is having its Tier 1 Load reduced due to annexation. The Existing Public gaining Tier 1 Load as a result of the annexation will have its RICm recalculated based on the weighted average of its prior annexation Tier 1 Load and associated RICm and the annexed Tier 1 Load and the RICm associated with that load.

4.5.2.3 Product Switching and RICm

In the event a customer with a negative RICm (*i.e.*, the RICm reduces the amount the customer pays BPA) switches products during the contract duration, their RICm will be eliminated starting in the Rate Period the product switch becomes effective. In the event a customer with a positive RICm (*i.e.*, the RICm increases the amount the customer pays BPA) switches products during the contract duration, their RICm will remain unchanged from the amounts and schedule as established through the BP-29 7(i) Process.

4.6 Other Tier 1 Charges

BPA will limit Tier 1 Rates and Charges to those detailed in this Chapter 4. These limitations pertain to the Core charges of the PF rate design, which include Tier 1 Energy

Charges, Demand Charges, and PLVCs, and do not encompass other adjustments, charges, and special rate provisions (e.g., customer-specific charges and credits, targeted adjustment charges, unauthorized increase charges, conservation charges, credits, or surcharges), or any other charges allowed under Section 9.4. These limitations do not apply to rate adjustments developed and assessed for risk mitigation (e.g., application of a Cost Recovery Adjustment Clause (CRAC)), new or modified risk mitigation tools, or mid-Rate Period rate adjustments for cost recovery purposes. Further, the PRDM does not in any way limit or constrain the way in which BPA recovers its conservation costs from its customers —for example within the PF Public Rate Pool, BPA could adopt cost allocations for conservation-related charges, in a 7(i) Process. The revenue associated with any conservation charges would be allocated to the Composite Cost Pool. In addition, BPA may also, without revising the PRDM, impose separate rates for product and service switching, which will be developed as needed in the applicable 7(i) Process. If, notwithstanding the limitations expressed here, BPA or a party in a 7(i) Process wishes to institute a new rate or charge, it may pursue a revision to this PRDM to reflect such new rate or charge in accordance with the provisions in Chapter 9..

4.7 Disaggregation of Risks within Tier 1 Non-Slice Products

Beyond the Core charges defined above, the PRDM will not further sub allocate costs associated with risks between Slice and Non-Slice products prior to September 30, 2044. This prohibition of a further sub allocation of risk is limited to Tier 1 Rates and does not apply to any other rates, products, or services that BPA may provide, such as Tier 2 Rates and other PF and non-PF rates, products, and services. Any sub allocation of risk in Tier 1 Rates after September 30, 2044, would be decided through a 7(i) Process.

During the public workgroups and workshops that facilitated the creation of the PRDM, a concern was raised about risk and the potential that the allocation of risk across PF Public customers purchasing power applicable to this PRDM may need to be evaluated at a more granular level than Slice and Non-Slice. Customers discussed the allocation of risk to Load Following differently than Block or by each utility's load characteristics. While the concept was deemed plausible and may prove to be supported by the principle of cost causation, the consensus was that we did not have enough data, systems, and tools to effectively either prove or disprove the merits of the concept, and linkage to rate design before September 30, 2044.

4.8 Cashflow Considerations

Because the Tier 1 rate design may result in within-year cash flow impacts to customers, BPA may, if practicable, and consistent with BPA's statutory obligation to ensure timely cost recovery, accommodate individual customer requests to reshape charges within the Fiscal Year to mitigate adverse cash flow effects on the customer. Such reshaping of charges must recover the same amount of dollars on a net present value basis within the Fiscal Year as would have been recovered without the reshaping. The reshaping of the payments must be mutually agreed upon by both BPA and the customer prior to the start of the Rate Period. Absent agreement, the customer will pay the Energy Charges without reshaping.

The reshaping of the Energy Charges will take into account the cash-flow impacts to the customer of a forecast of Energy Charges; a forecast of Demand Charges; and a forecast of Peak Load Variance Charges. The forecast cash-flow impacts to the customer will be mitigated by including fixed dollar monthly credits and debits that recover, in total, the same amount of dollars on a net present value basis. The fixed dollar monthly credits and debits will not impact any rate or billing determinant. To accommodate reshaping requests, BPA will take into account the potential offsetting impacts of multiple reshaping requests. BPA may prorate multiple reshaping requests if necessary to avoid or mitigate material adverse impacts on BPA's cash flow.

5 TIER 2 RATE DESIGN

Chapter objectives: This chapter is largely a redline as opposed to a rewrite. These changes are driven by the overall Core design changes developed in the PRDM Public Process in 2024—and highlight several key revisions.

Consistent with the provisions below, the specific rate designs for BPA's Tier 2 Rate Alternatives will be determined in each 7(i) Process. BPA's allocation of costs to the Tier 2 Cost Pools associated with the Tier 2 Rate Alternatives will be subject to the provisions of this PRDM. The allocation of Tier 2 Costs and the design of Tier 2 Rates will ensure to the maximum extent practical that the Tier 2 Rates will recover the full allocated cost of BPA service to planned Above-CHWM Load. The Tier 1 System will not be used in a manner that subsidizes the allocated costs of Tier 2 Rate service.

5.1 Overall Tier 2 Construct

Each customer will elect, in its Power Sales Contract, how its Above-CHWM Load will be served during the contract term. The customer will choose whether and how its Above-CHWM will be served by electing the Long-Term Tier 2 Path, the Flexible Above-CHWM Path, or a combination of the two paths. Above-CHWM Load under the Long-Term Tier 2 Path is served by BPA under its Tier 2 Long-Term Alternative at the Tier 2 Long-Term Rate. Above-CHWM Load under the Flexible Above-CHWM Path could be served by a combination of the customer's non-Federal resources, BPA's Tier 2 Short-Term Alternative at the Tier 2 Short-Term Rate, and BPA's Tier 2 Vintage Alternatives at the applicable Tier 2 Vintage Rate.

BPA will establish only one Tier 2 Long-Term Rate for each year, and one Tier 2 Short-Term Rate for each year. BPA may establish multiple Tier 2 Vintage Rates as BPA may provide multiple distinct Tier 2 Vintage Alternatives within a year, and each would have its own rate based on the cost of the resources specific to each distinct Tier 2 Vintage Alternative. Each customer electing a particular Tier 2 Rate Alternative will pay the rate associated with the Tier 2 Rate Alternative Service. Each Tier 2 Rate will be established to recover all the Tier 2 Costs allocated to that Tier 2 Rate Alternative plus any adders to account for real power losses, overhead costs, other costs, and other services being provided from BPA to support power sold at each Tier 2 Rate. BPA will establish Tier 2 Rates based on the cost of providing a flat annual block of power.

Any Forecast Firm Inventory used to provide service at Tier 2 Rates will be priced at the marginal value of such power, except Forecast Firm Inventory used to provide service at the Tier 2 Long-Term Rate, which will be at a rate equivalent to BPA's Tier 1 Rates.

5.1.1 Setting Tier 2 Amounts

The amount of power purchased by a customer under BPA's Tier 2 Rate Alternatives is established in the CHWM Process consistent with each customer's Above-CHWM Load elections. The CHWM Process concludes before Tier 2 Rates are set in the 7(i) Process. Above-CHWM Load served at Tier 2 Rates will be in fixed, annual amounts on a take-or-pay basis for each Fiscal Year of a Rate Period. To support operational convenience, a Load Following customer that elects the Flexible Above-CHWM Path can also elect to have up to

0.999 aMW of its Above-CHWM Load served through the Core Rate Design as described in Chapter 4.

5.2 Cost Basis

As described in Section 2.2.4, BPA will identify which of its costs are Tier 2 Costs and to which Tier 2 Cost Pool the costs will be allocated for calculating each Tier 2 Rate in the applicable 7(i) Process. Additionally, Section 3.6 contains guidance regarding the allocation of specific resource costs.

5.2.1 Cost Component Construct

The costs included in each of the Tier 2 Cost Pools will be BPA's costs associated with serving the customers who elect service at the corresponding Tier 2 Rate Alternative.

For a Tier 2 Rate Alternative based on block energy purchases from market sources, the costs allocated to that Cost Pool will include costs that BPA incurs to serve load at a set, or variable, price with a combination of forward and spot purchases of block energy from the market. When this type of Tier 2 Rate is set, BPA may not have made all the market purchases needed to serve the loads at this rate. Consequently, this type of rate may be comprised of both known and projected costs of the energy from market purchases, a risk component to cover the expected risks of providing service at a set forward price (which could take the form of some combination of planned net revenues for risk and rate adjustments or true-ups), plus any adders to account for real power losses, risk, overhead costs, and other costs being incurred and services being provided by BPA to support power sold at that specific Tier 2 Rate. See Section 5.2.3 for the construct of the Overhead Cost Adder.

For a Tier 2 Rate Alternative based on non-dispatchable resources, the costs allocated to that Tier 2 Cost Pool will include costs BPA incurs to serve load with a purchase of the specific non-dispatchable resource. These types of costs may include the cost of the resource purchase, transaction costs, the cost of providing Resource Support Services (RSS), plus any adders to account for real power losses, risk, overhead costs, and other costs being incurred or services being provided by BPA to support power sold at that specific Tier 2 Rate. Transaction costs might include transmission and Balancing Authority Area charges for within-hour balancing. Transaction costs may be known or be based on projections that are trued up after the fact. The cost of providing RSS would be at the same rates as those that would be applied to a customer's purchase of a non-dispatchable Non-Federal Resource to convert the resource delivery to the financial equivalent of a flat annual block.

For a Tier 2 Rate Alternative based on dispatchable resources, the costs allocated to that Tier 2 Cost Pool will include costs and risks that BPA incurs to serve load with a purchase of a dispatchable resource, with the customer assuming the operational risks. These types of costs include projected annual fixed costs (debt service and fixed O&M) of the resource; the expected fuel and variable O&M costs of the resource based on its expected operation; a mechanism to true up the expected fuel and variable O&M costs to actual costs; the cost of operating reserves and replacement power for outages; a mechanism to compensate the customer for any savings from economic dispatch of the resource, including fuel remarketing proceeds; costs of transmission services, if any, to transmit power to the federal system; transaction costs; plus any adders to account for real power losses, risk, overhead costs, and other costs being incurred or services being provided by BPA to support power sold at that specific Tier 2 Rate.

A Tier 2 Alternative Cost Pool can include combinations of market purchases and resource costs, as described above. Tier 2 Rates can be fixed for a Rate Period or be subject to true-ups, surcharges, and other adjustments to support collecting BPA's cost of providing a Tier 2 Rate Alternative from the customers who elect service at the corresponding Tier 2 Rate Alternative.

5.2.2 Resource Support Services

Tier 2 Rates based on the costs of resources acquired by BPA to serve Above-CHWM Loads will include appropriate RSS charges necessary to price the service as if the resource output is serving a flat annual load. RSS supplied by BPA for resources serving loads at Tier 2 Rates will ensure energy neutrality, and RSS capacity-related charges will compensate the Composite Cost Pool for the value of the RSS and for risk exposure incurred due to the provision of RSS. RSS may include energy-related and other charges. The revenue from these other charges will be allocated to the Cost Pool based on cost causation principles, such as allocating RSS energy-related charges to the Non-Slice Cost Pool if BPA's Balancing Power Purchases cost, which are also allocated to the Non-Slice Cost Pool, are being impacted as a result of BPA providing RSS. The forecast costs for RSS used to calculate each Tier 2 Rate will be set in each 7(i) Process for each Rate Period.

5.2.3 Overhead Cost Adder

Each Tier 2 Cost Pool will include an Overhead Cost Adder. This adder will provide an offset to the Composite Cost Pool for the general and administrative (overhead) costs associated with BPA's provision of power at Tier 2 Rates. In each 7(i) Process, BPA will propose an Overhead Cost Adder to be applied to all power sold at Tier 2 Rates (mills/kWh). The adder will be set at a level that will reasonably compensate the Composite Cost Pool for the costs of providing the service, which BPA expects would be comparable to typical electricity broker fees.

5.3 Remarketing of Tier 2 Amounts

If BPA remarkets a customer's Tier 2 purchase obligation pursuant to the Power Sales Contract, then BPA will credit the proceeds (net of any remarketing costs as described in Section 6.4.1 below) to such customer. The customer must continue to pay for the entire purchase at the appropriate Tier 2 Rate.

5.3.1 Calculating the Remarketed Tier 2 Rate Proceeds

If BPA remarkets for a customer any Tier 2 Rate Alternative purchase obligation, the proceeds (as established below) obtained from such remarketing will be netted against the customer's monthly bill. BPA will calculate the applicable rate, or rates, used to calculate the proceeds for the remarketed energy in the each 7(i) Process. The total proceeds of the remarketed energy will be reduced for aggregated transaction costs, including, but not limited to, such costs as broker or other marketing fees, transmission costs, transmission losses, and odd lot remarketing costs. Transaction costs also could include a risk component or adjustment mechanism for the risk associated with the potential difference between forecast and actual market prices.

The customer will remain responsible for paying any charges and adjustments that otherwise would have been paid had BPA not had to provide remarketing. Remarketing of Tier 2 Rate Alternative purchase obligation amounts that include a transfer of RECs will not affect any transfer of RECs associated with such amounts. This procedure will be applied whether or not BPA actually remarkets the power or uses it for its own purposes.

5.4 Tier 2 Long-Term Alternative

5.4.1 Tier 2 Long-Term Change Fee and Charge

Pursuant to the terms in the customer's Power Sales Contract, a customer may elect to change (cap or reduce) its Tier 2 Long-Term Alternative election. A Tier 2 Change Fee and a Long-Term Tier 2 Change Charge will apply if this change in original election is made

1) after Bonneville acquires power for the purposes of serving Long-Term Tier 2 Path obligations, or 2) after August 1, 2027, whichever occurs first. The Tier 2 Change Fee will be established in each 7(i) Process and shall be no lower than 0.05 mills/kWh applied to the customer's Tier 1 Load amount for the remaining term of the CHWM Contract. The Long-Term Tier 2 Change Charge will be based on costs BPA determines would otherwise be spread to other Long-Term Tier 2 Path customers, calculated independent and without consideration of the Tier 2 Change Fee, as a result of the change in election. The revenue received from the Tier 2 Change Fee and the Long-Term Tier 2 Change Charge will be credited to the Tier 2 Long-Term Cost Pool.

5.4.2 Tier 2 Long-Term Cost Reallocation Provision

If the Tier 2 Long-Term Cost Pool contains costs and BPA has no load being served at the Tier 2 Long-Term Rate, BPA will reallocate such costs to all customers that elected any portion of their potential Above-CHWM Load to be served under the Tier 2 Long-Term Alternative. This reallocation will be spread across all such customers' Rate Period forecast Tier 1 Energy Charge Billing Determinants.

Similarly, if a subset of customers that elected BPA's Tier 2 Long-Term Alternative are determined to be bearing an inequitable amount of the costs allocated to the Tier 2 Long-Term Cost Pool, BPA will determine, through the 7(i) Process, the portion of the Tier 2 Long-Term Cost Pool to be reallocated to all customers that elected any portion of their potential Above-CHWM Load be served under the Tier 2 Long-Term Alternative. This reallocation will be spread across all such customers' Rate Period forecast Tier 1 Energy Charge Billing Determinants.

5.5 Starting the Process for Establishing a Tier 2 Vintage Alternative

When BPA determines it will attempt to make an acquisition of the output of a physical resource to meet its load obligations for a period that extends beyond a 3 year period, BPA will notify customers with a CHWM Contract at least 90 calendar days prior to making its Request For Offer (RFO). The intent of this notice is to facilitate the potential creation of a Tier 2 Vintage Alternative by allowing a CHWM Contract customer an opportunity to identify its interest in creating a Tier 2 Vintage Alternative from the same RFO. The maximum amount of power a customer can request to purchase under a Tier 2 Vintage Alternative would be set equal to its annual maximum forecast of the customer's future Above-CHWM Load; subject to the Flexible Above-CHWM Path less any non-Federal resources serving that Above-CHWM Load. When a customer purchases power under a Tier 2 Vintage Alternative that is in excess of its then current Above-CHWM Load, BPA would treat such power as either: 1) an advanced sale of surplus power to be managed by the customer; or 2) excess power to be managed by BPA through a remarketing service, see Section 5.3, until the customer's load grows into its Tier 2 Vintage amount.

6 RESOURCE SUPPORT SERVICES

Chapter objectives: This chapter focuses on pricing and moves service descriptions previously in the TRM document. This chapter intends to link RSS-related capacity component pricing to a marginal capacity cost, and link energy components to a market price determined in each 7(i) Process to allow flexibility to adjust to appropriate indices and timeframes.

Resource Support Services (RSS) are offered under the Power Sales Contract, and include multiple services to integrate non-Federal resources with load service. RSS are available for all specified Non-Federal Resources that Load Following customers contractually dedicate to serve their TRL, and for specified new renewable resources Block customers contractually dedicate to serve their TRL. The suite of RSS and their design may change over time as proposed and adopted in an applicable 7(i) Process.

6.1 RSS Pricing Principles

RSS will be priced comparably across Load Following and Block products. RSS may include, but is not limited to, providing scheduling services, providing additional Federal capacity to help the customer meet its contractual obligations with BPA, or to firm up variable generation. Generally speaking, the capacity component of each Resource Shaping Service will be priced at a marginal cost of capacity, such as the Marginal Capacity Resource used to set the Demand Rates; and any applicable energy components will be priced at a market-based price of energy for the appropriate time period for the particular RSS service. Other costs, such as the cost of providing scheduling services, could be based on relevant portions of BPA's Revenue Requirement or on the cost charged by other entities to provide a similar service. The price of capacity, the price of energy, and the allocation of any other costs for RSS offered by BPA will be determined in each 7(i) Process. The revenue received from providing RSS will be allocated to the Cost Pool based on cost causation principles – such as allocating capacity-related revenue to the Composite Cost Pool to compensate for the associated Designated System Obligation, or to the Non-Slice Cost Pool to offset impacts to BPA's Balancing Power Purchases cost that are otherwise allocated to the Non-Slice Cost Pool.

6.2 Treatment for Load Following Dedicated Resources that are Existing Resources

BPA will apply a Forced Outage Reserves Service (FORS)-based fee to all Load Following customer's Dedicated Resources and Existing Resources. The FORS-based fee allows an Existing Resource dedicated to a Load Following customer's load to produce generation below its Exhibit A amounts under conditions defined in the Power Sales Contract (such as MWh limits, frequency of occurrence, qualifying events, and notice requirements) and pay a market-based rate, as established in each 7(i) Process and inclusive of potential upward adjustments to reflect transaction and other costs, for the energy shortfall without incurring an Unauthorized Increase Charge.

The FORS-based fee also allows eligible resources, as defined by the Power Sales Contract, to receive a market-based energy credit, as established in each 7(i) Process and inclusive of potential downward adjustments to reflect transaction and other costs, for amounts of energy produced by the resource in excess of its Exhibit A amounts. In order to avoid double counting, only the Exhibit A amounts will be used for purposes of calculating billing determinants as described in Chapter 4 of the PRDM.

7 RISK MITIGATION

Chapter objectives: Broad principles remain from the TRM.

In each 7(i) Process, BPA will establish risk mitigation mechanisms and set rates that are consistent with BPA's then-current agency financial risk standard(s), as set out in BPA's then-current financial plan and policies.

The CHWM Contract includes take-or-pay provisions that obligate each customer to pay its monthly BPA power bills calculated using the Tier 1 and Tier 2 Rates applicable to each customer.

7.1 Risk in Tier 2

Risks in Tier 2 will be assessed in each 7(i) Process, both for each Tier 2 Rate Alternative and collectively for all Tier 2 Rate Alternatives to determine if the terms and conditions have mitigated such risks sufficiently to meet BPA's risk standards. In addition to such terms and conditions, BPA will include in Tier 2 Rates any supplementary risk mitigation necessary to meet BPA's risk standards. Altogether, Tier 2 risk mitigation will be structured so that the risk associated with Tier 2 Rates will not increase the costs allocated to Tier 1 Cost Pools or require any enhancement of Tier 1 risk protection mechanisms beyond what would have been required absent sales at Tier 2 Rates. BPA recognizes that it may be limited in Tier 2 Rate offerings by the foregoing requirements that Tier 2 risks not increase costs allocated to Tier 1 or require enhancement of Tier 1 risk protections.

In each 7(i) Process, when there is more specificity about the resource and purchase costs allocated to the various Tier 2 Cost Pools, BPA will assess the risks of providing service at the various Tier 2 Rate Alternatives. BPA will propose risk mitigation tools for each Tier 2

Cost Pool (e.g., Planned Net Revenues for Risk (PNRR), CRACs, true-ups to actual costs), as appropriate.

7.2 Risk in Tier 1

In each 7(i) Process, BPA will assess the risks related to the costs and revenues allocated to the Tier 1 Cost Pools, design risk mitigation measures, and set the Tier 1 Rates to meet BPA's risk standard(s). Such measures may include PNRR, CRACs, true-ups to actual costs, and other measures determined appropriate by BPA.

The primary financial risk mitigation measures for the Slice Product are the transfer of the net secondary revenue risk to Slice purchasers (by providing them with secondary energy instead of a rate credit for anticipated net secondary revenues) and the Slice True-Up (see Section 2.7 for more information).

7.3 Assessment of Aggregate Risk

If, after assessing and mitigating risks for each Tier 2 Cost Pool and for Tier 1 Cost Pools, BPA finds that Power function risks have not been adequately mitigated pursuant to BPA's risk standards, then BPA will allocate the remaining risk and any additional mitigation between the tiers in the applicable 7(i) Process, consistent with this PRDM.

8 OTHER RATE DESIGN

Chapter objectives: This chapter is largely unchanged from the TRM. Specific changes are made to eliminate the application of the LDD to the A-CHWM "gross up" amount. Also, the discussion of the discounts removes reference to a TOCA billing determinant.

This chapter identifies and describes certain other public rates linked to Tier 1 and Tier 2 in addition to Core rates. These rates include: Rates for Unanticipated Load, Low Density Discount, Irrigation Rate Discount, and PF Exchange.

8.1 Rates for Unanticipated Load

BPA will develop rates in the applicable 7(i) Process for service to unanticipated loads (e.g., due to delay in the start-up of a specified new Non-Federal Resource). Unanticipated loads are public preference loads that BPA is obligated to serve under its statutes, but of which BPA has not had the notice to serve as required by the Power Sales Contract or General Rate Schedule Provisions (GRSPs) for a customer to receive service at Tier 1 or Tier 2 Rates. The GRSPs developed in the applicable 7(i) Process will establish the terms and conditions for application of these rates. These rates are intended to reflect the costs associated with the power and services needed to serve such load.

Load that BPA does not have an obligation to serve may face an unauthorized increase (UAI) charge. For example, if a customer does not provide for serving load when a Non-Federal Resource has an outage, and BPA delivers power, such power deliveries would be charged the UAI.

8.2 Low Density Discount

In the applicable 7(i) Process, BPA will apply a long-term Low Density Discount (LDD) that will remain in effect for multiple Rate Periods to the extent permitted by Section 7(d)(1) of the Northwest Power Act. The LDD benefit to a JOE will be equivalent to the sum of LDD benefits calculated for all eligible individual members of the JOE. BPA will determine the LDD for the JOE based on each such individual utility member's LDD amount.

The LDD will apply to the following Tier 1 charges: Composite Tier 1 Energy Charge, the Non-Slice Tier 1 Energy Charge, The Slice Tier 1 Energy Charge, the Demand Charge, and the Peak Load Variance Charge. LDD will not apply to purchases of power for Above-CHWM Load. The cost of the LDD program will be allocated to the Composite Cost Pool. The discount will be determined using the LDD Percentage Discount Table, as published in the applicable GRSPs.

In the applicable 7(i) Process, BPA will apply an LDD Percentage Discount Table that is the same as or similar to the example Table 8.1. The table will be formulated so that the resulting LDD program cost is forecast to be between $42 million and $44 million on average per year during the BP-29 Rate Period. This program cost may include utility-specific adjustments intended to temporarily mitigate a loss in program benefits to a utility deemed to be materially impacted by the change in LDD methodology from the TRM to the PRDM. This program cost above is comparable to the program costs prior to the effective date of the PRDM.

The eligibility requirements of C/M (consumers per mile of line) and K/I (kWh to investment ratio) will initially be calculated in the same manner as was the case in BP-26 Rate Period. BPA may, in a later 7(i) Process, propose changes to the eligibility requirements, LDD Percentage Discount Table, and definitions. Additionally, the definitions in the GRSPs may be adjusted to accommodate changes to distribution systems, including underground distribution lines, where appropriate.

8.3 Irrigation Rate Discount

Beginning with the FY 2029 Rate Period and continuing through the term of the Power Sales Contracts, BPA will include an Irrigation Rate Discount (IRD) in BPA's wholesale power 7(i) Process initial rate proposals in the form of a fixed percentage discount on the Tier 1 Rates. Eligible irrigation loads will be identified in a customer's Power Sales Contract and will not increase during the term of the contract. The discount will not apply to loads served at Tier 2 Rates.

The IRD benefit to a JOE will be equivalent to the sum of IRD benefits calculated for all eligible individual members of the JOE. BPA will determine the IRD benefit for the JOE based on each such individual utility member's IRD benefit.

In the applicable 7(i) Process, BPA will apply a fixed IRD percentage that will remain for the term of the contract. The IRD percentage will be set by calculating the value which will result in a program cost of approximately $22 million in FY 2029, when applied to eligible irrigation loads in that year. This program cost above is comparable to the program costs prior to the effective date of the PRDM.

Each Rate Period, BPA will use the IRD percentage to set a mills/kWh discount rate, that when applied to qualified irrigation load produces a dollar credit on eligible customers' power bills. The percentage will be multiplied by the sum of the forecast revenue that irrigation loads will pay through the Tier 1 Charges, adjusted for any applicable LDD, divided by the sum of the irrigation loads (expressed in kWh) to derive the mills/kWh discount. This discount will be seasonally available to qualifying loads during May, June, July, August, and September.

The Power Sales Contract will include the terms and conditions for the IRD. The Power Sales Contract also will specify quantities, definitions, and conditions for a qualifying irrigation load. The discount rate to be applied to qualifying irrigation loads for the relevant Rate Period will be determined in the applicable 7(i) Process and will be included in the applicable GRSPs.

BPA will include in the FY 2029 proposed GRSPs the eligibility criteria for the IRD. To qualify for the IRD, the customer must meet one of the following criteria:

1) The customer must have participated in BPA's IRD program in FY 2028.
2) At least 75 percent of the customer's Total Retail Load must be placed on BPA starting October 1, 2028, and the customer's irrigation rate schedule sales, May through September in FY 2018-2022, divided by its TRL for FY 2018-2022, is at least 5 percent; or, if less than 5 percent, the average kWh use for May through September in FY 2018-2022 (25 months/5 years) is 7,500,000 kWh or more.

Eligibility evaluation will be determined differently for existing and newly eligible Irrigation Rate customers. Eligibility evaluation for existing IRD customers will occur at signing of the Power Contract. Eligibility for new Irrigation Rate customers will be evaluated 90 calendar days after BPA issues the final PRDM ROD. Newly eligible IRD customers' Power Contracts will be amended to reflect the eligible kWh amounts.

For a Slice customer, BPA will apply the percentage reduction to the lesser of the customer's qualifying irrigation load (kWh) specified in its CHWM Contract or the sum of its monthly Block purchase at Tier 1 Rates plus the Slice Percentage of the monthly Tier 1 System Capability. No other charges or billing determinants will be affected.

There will be a true-up process at the end of each year's May through September irrigation season to ensure that the customer experienced the full amount of irrigation load stated in the Power Sales Contract. If a customer's May through September measured irrigation load is less than the amount of load eligible for mitigation, a true-up calculation will determine the amount the customer owes BPA at end of the irrigation season. The details and requirements of the true-up will be described in the applicable 7(i) Process and included in the GRSPs for each applicable Rate Period.

BPA will require IRD participating customers to implement cost-effective conservation measures on eligible irrigation systems in their service territories, as described in the GRSPs. The conservation measures may be eligible for future BPA conservation programs; the amount of BPA support will be determined through the 7(i) Process.

8.4 Section 7(b)(2) Rate Test

8.4.1 PF Exchange Rate for Customers with CHWM Contract

The PF Exchange Rate is not applicable to PF customers with a CHWM Contract.

8.4.2 PF Exchange Rate for Customers without a CHWM Contract

For customers that have not signed a CHWM Contract and have signed an RPS Agreement, BPA will establish a PF Exchange rate(s) in each 7(i) Process. Such rate(s) will be set consistent with the Northwest Power Act.

8.4.3 Section 7(b)(2) or Section 7(b)(3) Issues Not Addressed by PRDM

Notwithstanding any other provisions in this PRDM, this PRDM does not address, and therefore neither authorizes nor precludes, the allocation of section 7(b)(2) trigger amounts to BPA surplus sales, including secondary energy sales under the Slice product. Notwithstanding any other provisions in this PRDM, all issues pertaining to calculation of the section 7(b)(2) rate test and allocation of the section 7(b)(3) surcharge will be determined in the applicable 7(i) Process.

8.4.4 Determination of LDD Eligible Discount Percentage

For each customer, an eligible discount percentage will be determined using the table below. The eligible discount percentage will be the sum of the two potential discount percentages for which the customer qualifies. The total eligible discount percentage will not exceed 9 percent and may be adjusted pursuant to LDD Phase-In Adjustment, and Additional Adjustment for Very Low Densities.

Table 8-1
DETERMINATION OF LDD ELIGIBLE DISCOUNT PERCENTAGE

Percentage Discount	Applicable Range for kWh/Investment (K/I) Ratio	Applicable Range for Consumers/Mile (C/M) Ratio
0.0%	36 < X	12 < X
0.5%	33 < X ≤ 36	11 < X ≤ 12
1.0%	30 < X ≤ 33	10 < X ≤ 11
1.5%	27 < X ≤ 30	9 < X ≤ 10
2.0%	24 < X ≤ 27	8 < X ≤ 9
2.5%	21 < X ≤ 24	7 < X ≤ 8
3.0%	18 < X ≤ 21	6 < X ≤ 7
3.5%	15 < X ≤ 18	5 < X ≤ 6
4.0%	12 < X ≤ 15	4 < X ≤ 5
4.5%	9 < X ≤ 12	3 < X ≤ 4
5.0%	6 < X ≤ 9	2 < X ≤ 3
5.5%	3 < X ≤ 6	1 < X ≤ 2
6.0%	X ≤ 3	X ≤ 1

9 PRDM REVISION PROCESSES AND DISPUTE RESOLUTION

Chapter objectives: Combined TRM Chapters 12 and 13. Retained process for Improvements and Unintended Consequences. Mini-Trial for scope of Cost Recovery/Court Ruling, Irreconcilable Conflict within 7(i), and Irreconcilable Conflict outside 7(i).

In this Chapter 9:

Customer means a Public that purchases power from BPA at a Tier 1 Rate under a CHWM Contract.

Customer Group means a group comprised of not less than 45 percent of the customers (utility count).

9.1 General Provisions

9.1.1 Preliminary Revisions

It will be BPA's policy to revise the PRDM as little as possible. BPA reserves the right to revise the PRDM after February 1, 2009, but only in accordance with the criteria, conditions, and applicable processes set forth in this Section 9. Any revisions identified before February 1, 2009, must be agreed to by BPA and preference customer representatives designated by the Public Power Council, and will be proposed by BPA after that date in a future Section 7(i) rate proceeding, with the revisions not subject to the procedural requirements of this Section 9.

9.1.2 Process Generally Applicable to Any PRDM Revision

No revision to the PRDM may be made without the introduction, consideration, and adoption of such revision in a 7(i) Process. BPA will comply with the applicable requirements of this Section 9 when proposing revisions to the PRDM. In the event that a proposed revision to the PRDM has not satisfied the requirements for introduction in a 7(i) Process set out herein, then BPA shall neither propose nor adopt such proposed revision in a 7(i) Process until the applicable requirements of Section 9 are satisfied.

Except as provided in Section 9.2 (Improvements/Enhancements) and 9.3.2 (Unintended Consequences that affect only Customers), nothing in this Chapter 9 limits the positions that a customer may advocate in a 7(i) Process regarding the PRDM. Nothing in Chapter 9 either 1) precludes any party to a BPA 7(i) Process, other than a customer, from making any proposal or offering any testimony or other evidence on any matter that may otherwise be raised in a BPA 7(i) Process or 2) constrains any person or entity from taking any position with BPA on any issue outside of a 7(i) Process.

9.1.3 Core Provisions of the PRDM that May be Revised Only to Ensure Cost Recovery or Comply with Court Ruling

The provisions of the PRDM identified below cannot be revised except and unless the Administrator determines in accordance with the applicable procedures set forth in this Section that BPA cannot otherwise timely recover its costs or that the change is necessary to effectively comply with a court ruling:

2) The basic Tier 1 Rate design described in Section 5, consisting of the concept of three Tier 1 Cost Allocator (TOCA) customer Charges (Composite, Slice, and Non-Slice); the development of a Load-Shaping Charge for customers purchasing Block or Load-Following products; and Demand Charge Billing Determinants, which include a Contract Demand Quantity, as set forth in Section 5.3.

3) The establishment of Tier 2 Rates, as set forth in Chapter 6, that reflect the costs of resource acquisitions and purchases BPA must make to serve Above-RHWM Load.

4) Cost allocation principles set forth in Section 2.1.

9.1.4 Actions Not Considered to be a Revision to the PRDM

The Administrator reserves the discretion he or she otherwise possesses under law to establish, undertake, or otherwise address the following, including through implementation of the PRDM consistent with the terms thereof for those matters governed by the PRDM, in appropriate cases:

1) Calculation of actual rate levels.
2) Any rate issues identified in this PRDM that are specifically reserved for determination in a future 7(i) Process. These include, but are not limited to:
    a) Allocation of costs consistent with Sections 2.1, 2.2, and 2.3 and the Allocated Tiered Cost Table, Table 2
    b) The determination whether a line item in the Composite Cost Pool is subject to true-up (see Chapter 2).
    c) The addition of new Tier 2 cost pools (see Section 2.2).
    d) Methods used to solve for Tier 1 and Tier 2 Rates (see Section 2.2.1)
    e) Modifications to BPA's Power Services Statement of Revenues and Expenses (see Section 2.2.2)
    f) Allocations of New Expenses and New Credits (see Sections 2.3 and 2.7.3)
    g) Proposals to reallocate portions of the Tier 1 Secondary Energy Credit to Composite Cost Pool (see Section 2.4)
    h) Proposals for an alternative cost recovery mechanism (see Section 2.6)
    i) True-up of rate revenue credits (see Section 2.7.1.2.2)
    j) Revisions to MRNR treatment (see Section 2.7.1.2.2)
    k) Expenses and revenue credits (see Section 2.7.3)

l) Resources considered Tier 1 System Resources and respective firm power (see Section 3.1)

m) Adding Designated System Obligations and related issues (see Sections 3.2.2 and 3.2.3)

n) Forecasts of Rate Period P Augmentation (see Section 3.3)

o) The determination whether forecast costs of augmentation are subject to the Slice True-Up (see Section 3.3.2).

p) Forecasts of Balancing Power Purchases and adjustments (see Section 3.4)

q) Updates to Table 3.3, 3.4, and 3.5 (see Section 3.5, 3.6, and 3.7)

r) Tier 1 Energy Charges (see Section 4.1)

s) Composite Tier 1 Energy Rates (see Section 4.1.2)

t) Non-Slice Tier 1 Energy Rate (see Section 4.1.3)

u) Slice Tier 1 Energy Rate (see Section 4.1.4)

v) Marginal Energy True-Up Rate (see Section 4.2.3)

w) Adjustments to Marginal Capacity Resource and shape of monthly Demand Rates (see Section 4.3.4)

x) Capacity Credit (see Section 4.3.6)

y) Capacity planning standards, PLVC billing determinants, and market-based energy rate (see Section 4.4)

z) RICc recalculations (see Section 4.5.1.1)

aa) Rates for New Publics (see Sections 4.5.1.2 and 4.5.1.2)

ab) RICm phase-out schedule (see Section 4.5.2) ac) Recovery of conservation costs and rates for product and service switching (see Section 4.6)

ad) Sub-allocation of risk in Tier 1 Rates (see Section 4.7)

ae) Forecast costs for RSS (see Section 5.2.2)

af) Determination of the Overhead Cost Adder to Tier 2 Cost Pools (see Section 5.2.3)

ag) Calculations for remarketed energy (see Section 5.3.1)

ah) Tier 2 Change Fee (see Section 5.4)

ai) Design, pricing, and application of the RSS rates (see Section 6)

aj) FORS-based fee (see Section 6.2)

ak) Risk mitigation (consistent with Chapter 7)

al) Rates for Unanticipated Load (see Section 8.1)

am) Applicable of Low Density Discount (see Section 8.1)

an) Irrigation Rate Discount (see Section 8.2)

ao) Rate treatment for customers that execute non-CHWM contracts (see Section 8.3.2)

ap) Application of Sections 7(b)(2) and 7(b)(3) of the Northwest Power Act (see Section 8.3.3)

aq) Preliminary revisions (see Section 9.1.1)

3) PRDM Exhibits will be filled in and revised consistent with the terms of the PRDM.

4) Such other actions described in the PRDM that are to be determined in a Section 7(i) Process.

The actions described in this Section 9.4 do not constitute a "revision" to the PRDM.

9.2 Improvements and Enhancements

9.2.1 Criteria and Conditions for Improvements and Enhancements

Revisions to the PRDM not covered by Section 9.4 (Cost Recovery/Court Ruling), 9.1.4 (Core Provisions), or 9.3 (Unintended Consequences) and that are proposed by BPA or a Customer Group to improve and enhance the PRDM ("Improvement Proposal") must be made consistent with this Section 9.5.

9.2.2 Process for Improvements and Enhancements

BPA or a Customer Group may propose a revision to the PRDM as provided for in Section 9.2.1 only after complying with the requirements of this Section 9.2.2.

9.2.2.1 Notice

Before BPA or a Customer Group proposes in a 7(i) Process an Improvement Proposal, BPA or the Customer Group will notify all customers of the Improvement Proposal in advance of the 7(i) Process and the proponent's reasons 1) why the Improvement Proposal will improve or enhance implementation of the PRDM in a way that will continue to effectuate its purposes but be more cost-effective and efficient, customer responsive, readily implementable, or capable of fulfilling the PRDM's purposes and 2) how the value of the Improvement Proposal outweighs any harm created by it. The notice will specify the date by which each customer may express its support for the Improvement Proposal, and the means for registering its support.

9.2.2.2 Customer Approval

BPA or the Customer Group may propose in a 7(i) Process the Improvement Proposal only if it is approved by customers totaling both 1) at least 70 percent of customers (utility count) and 2) at least 50 percent of the sum of the CHWMs, with both of the foregoing measured by the individual vote of each customer. In determining the total, BPA shall count each abstention and absence of a vote as a vote that the customer does not approve the Improvement Proposal.

In the event that the customers approving the Improvement Proposal are less than the voting requirements of the preceding paragraph, then the Improvement Proposal will not be proposed in any 7(i) Process by BPA, the Customer Group, or any customer until the voting requirements in this Section 9.2.2 above are satisfied.

In the event that the customers approving the Improvement Proposal are equal to or more than the voting requirements of this Section 9.2.2, then BPA or the Customer Group may propose the Improvement Proposal in a 7(i) Process. The Improvement Proposal will be considered in the normal course through the 7(i) Process with a decision in the Administrator's Record of Decision.

9.3 Revisions for Unintended Consequences

9.3.1 Criteria and Conditions for Revisions for Unintended Consequences

With the exception of PRDM changes that are constrained by Section 9.1.4 (Core Provisions) or implementation of the PRDM reserved by Section 9.1.5 (Expressly Not Revisions), BPA may, in accordance with the applicable procedures of this Section 9, propose revisions in the PRDM to address or avoid unintended consequences that put at risk the Principles and Goals underlying the PRDM as set forth in Section 1.1 of the Provider of Choice Policy.

9.3.2 Process for Revisions for Unintended Consequences that *Do Not* Affect Others or General Policies

9.3.2.1 Procedures Not Applicable if Unintended Consequences Affect Others or General Policies

The procedures set forth in this Section 9.6.2 apply only to revisions to the PRDM as provided for in Section 9.6.1 that address or rectify unintended consequences of the PRDM that affect only customers with CHWM Contracts, or that do not affect or affect only in a *de minimis* manner the IOU or DSI customers of BPA or BPA customers that are not eligible for or do not take service under CHWM Contracts ("Unintended Consequence Proposal"). Such procedures do not apply to, and an Unintended Consequence Proposal does not encompass, proposed revisions to the PRDM that are necessary to address or rectify unintended consequences of the PRDM that affect BPA programs or policies of general application (e.g., the unintended consequence affects programmatic responsibilities such as fish and wildlife, conservation, or transmission).

BPA or a Customer Group may propose an Unintended Consequence Proposal in a 7(i) Process only after complying with the requirements of this Section 9.6.2.

9.3.2.2 Notice

Before such an Unintended Consequence Proposal is introduced in a 7(i) Process by BPA or a Customer Group, BPA will notify all customers in advance of the 7(i) Process of the Unintended Consequence Proposal and the proponent's reasons 1) why the Unintended Consequence Proposal will address or rectify the unintended consequence that puts at risk the Principles and Goals underlying the PRDM as set forth in Section 1.1 of the Provider of Choice Policy and 2) how the value of the Unintended Consequence Proposal outweighs any detriment created by it. The notice will specify the date by which each customer may object to the Unintended Consequence Proposal and the means for registering its objection.

9.3.2.3 Customer Objection

BPA or the Customer Group may propose in a 7(i) Process the Unintended Consequence Proposal unless it is objected to by customers totaling both 1) at least 70 percent of customers (utility count) and 2) at least 50 percent of the sum of the CHWMs, with both of the foregoing measured by the individual vote of each customer. In determining the total, BPA shall count each abstention and absence of a vote as a vote that the customer does not object to the proposed change.

In the event that the customers objecting to the Unintended Consequence Proposal equal or exceed the voting requirements of the preceding paragraph, then BPA, the Customer Group, or any customer shall not propose in any 7(i) Process the Unintended Consequence Proposal until the voting requirements of this Section 9.3.2 are satisfied.

In the event that the customers objecting to the Unintended Consequence Proposal are less than the voting requirements of this Section 9.3.2, BPA or the Customer Group may propose in a 7(i) Process the Unintended Consequence Proposal. The Unintended Consequence Proposal will be considered in the normal course through the 7(i) Process with a decision in the Administrator’s Record of Decision.

9.3.3 Process for Revisions for Unintended Consequences that *Do* Affect Others or General Programs or Policies

Any proposals to revise the PRDM to address unintended consequences that affect others or general programs or policies (*i.e.,* within the scope of Section 9.5.1, but not within the scope of Section 9.5.2), may be proposed and considered in the normal course through the 7(i) Process, with a decision in the Administrator's Record of Decision.

9.3.3.1 Notice

However, before such a proposal is considered in a 7(i) Process by BPA or a Customer Group, BPA will notify all customers of the proposal and the proponent's reasons 1) why the proposal will address or rectify the unintended consequence that puts at risk the Principles and Goals underlying the PRDM as set forth in Section 1.1 of the Provider of Choice Policy and 2) how the value of the proposal outweighs any detriment created by it.

9.4 Revisions to PRDM to Ensure Cost Recovery or Comply with Court Ruling

9.4.1 Criteria and Conditions for Revisions for Cost Recovery or Court Ruling

BPA reserves the right to revise any part of this PRDM if the Administrator has determined in accordance with the applicable procedures set forth in Chapter 9 that: 1) BPA cannot timely and reasonably recover its costs without revising the PRDM; or 2) a revision to the PRDM is necessary to effectively comply with a court ruling. For purposes of this PRDM, reference to a court ruling shall be deemed to include a ruling of the Federal Energy Regulatory Commission that disapproves or remands a BPA rate based on the PRDM.

9.4.2 Process for Revisions for Cost Recovery or Court Ruling

BPA will propose only those revisions under Sections 9.4.1 that are necessary to comply with a court ruling or ensure cost recovery ("Recovery/Response Proposal") and will seek to limit both the number and scope of such revisions.

9.4.2.1 Preliminary Procedures Specific to Revisions for Cost Recovery

Before proposing any revision to the PRDM to ensure timely cost recovery, to the extent practicable BPA will take the following steps:

1) BPA will make reasonable efforts to recover the costs from the party(s) that would otherwise be responsible for such costs. Such efforts may include making demand on any available credit support and pursuing legal action when appropriate.
2) BPA will make good faith efforts to reduce BPA power costs so as to offset the cost that would otherwise occasion the need for a change in the PRDM to ensure cost recovery.
3) If the cost recovery problem is occasioned by the design of the PRDM, BPA will convene a public meeting with customers and interested parties to discuss alternatives to a revision of the PRDM.
4) After taking such steps, BPA will issue a report to customers and interested parties regarding the efforts, including those listed (1-3) above, that the Administrator has taken before resorting to a revision to the PRDM, and why the set of safeguards BPA followed when entering identified transactions (e.g., service at a Tier 2 Rate) was not sufficient to avoid the cost recovery problem.

These criteria, or disputes over whether the Administrator has satisfied them, do not override and will not be allowed to frustrate the Administrator's responsibility to establish rates to recover costs and timely repay the U.S. Treasury.

9.4.2.2 Customer Petition for Mini-Trial Disputing Response/Recovery Proposal

Customers that are party to a 7(i) Process may petition for a Mini-Trial alleging the Recovery/Response Proposal is not necessary to ensure cost recovery or respond to court ruling, and/or that the Recovery/Response Proposal is unreasonably disproportionate to what is needed to comply with the court ruling or to ensure cost recovery, compared to the alternative proposal(s), if any, offered by the customer(s).

A written petition so disputing the Response/Recovery Proposal may only be filed with the Hearing Officer within 20 Business Days after submission of BPA's initial proposal in such 7(i) Process, or within 10 Business Days after an Administrator's Mini-Trial decision under Section 9.6.4(iii). The petition may be filed only if it is approved by customers who are party to the 7(i) Process in their individual capacity and customers who are members of groups and organizations such as the Pacific Northwest Generating Cooperative or the Public Power Council that are parties to such process totaling both 1) at least 70 percent of such customers (utility count), and 2) at least 50 percent of the sum of the CHWMs, with both of the foregoing measured by the individual vote of each customer.

Upon receipt of such petition, the Hearing Officer shall expeditiously schedule, consistent with the rate case schedule and the procedural requirements of Section 9.6 (Mini-Trial), a Mini-Trial regarding whether BPA's Response/Recovery Proposal is necessary to ensure cost recovery or respond to a court ruling as provided for in Section 9.4.1, and/or whether the Response/Recovery Proposal is unreasonably disproportionate to what is needed to comply with the court order or to ensure cost recovery, compared to the alternative proposal(s), if any, offered by the customer(s).

If no such petition is timely filed, the Recovery/Response Proposal will be considered in the normal course through the 7(i) Process with a decision in the Administrator's Record of Decision.

9.5 Disputes Alleging Irreconcilable Conflict with the PRDM

9.5.1 Criteria and Conditions for Determining an Irreconcilable Conflict Exists

An Irreconcilable Conflict exists only when:

1) The PRDM clearly and unambiguously requires or prohibits an action, and an action or inaction proposed by BPA (the "BPA Position") is contrary to such requirement or prohibition; or
2) The PRDM is silent, ambiguous, or leaves a gap regarding the matter in question, and the BPA Position cannot be reconciled with any reasonable interpretation of what the PRDM does provide for.

9.5.2 Customer Petition for Mini-Trial Alleging Irreconcilable Conflict within a 7(i) Process

Customers that are party to a 7(i) Process may petition for a Mini-Trial alleging that a BPA Position in such 7(i) Process is in Irreconcilable Conflict with the PRDM.

A written petition so alleging may only be filed with the Hearing Officer within 20 Business Days after submission of BPA's initial proposal in a 7(i) Process. The petition may be filed only if it is approved by customers totaling both 1) at least 70 percent of such customers (utility count) and 2) at least 50 percent of the sum of the CHWMs of all such customers, with both of the foregoing measured by the individual vote of each customer. Such petition must allege that 1) a BPA Position in the 7(i) Process is in Irreconcilable Conflict with the PRDM; 2) BPA has not sought to revise the PRDM to reconcile it with the BPA Position; and 3) such customers oppose the BPA Position.

Upon receipt of such petition, the Hearing Officer shall expeditiously schedule, consistent with the rate case schedule and the procedural requirements of Section 9.6 (Mini-Trial), a Mini-Trial regarding whether the BPA Position is in Irreconcilable Conflict with the PRDM.

If no such petition is timely filed, the BPA Position will be considered in the normal course through the 7(i) Process with a decision in the Administrator's Record of Decision.

7(i) Process7(i) Process7(i) Process

9.5.3 Customer Petition for Mini-Trial Alleging Irreconcilable Conflict Outside a 7(i) Process

Customers may petition for a Mini-Trial alleging that a BPA final action, other than the Administrator's Record of Decision following a 7(i) Process, is in Irreconcilable Conflict with the PRDM.

A written petition so alleging may only be submitted to the Administrator within 20 Business Days after a BPA final action. The petition may be filed only if it is approved by customers totaling both 1) at least 70 percent of such customers (utility count) and 2) at least 50 percent of the sum of the CHWMs of all such customers, with both of the foregoing measured by the individual vote of each customer. Such petition must allege that 1) a BPA final action is in Irreconcilable Conflict with the PRDM; and 2) such customers oppose the BPA final action.

Upon receipt of such petition, the Administrator shall expeditiously schedule, consistent the procedural requirements of Section 9.6 (Mini-Trial), a Mini-Trial regarding whether the BPA final action is in Irreconcilable Conflict with the PRDM.

9.6 Mini-Trial Before the Administrator

If a Mini-Trial is scheduled pursuant to Section 9.4 (Cost Recovery/Court Ruling) or 9.5 (Irreconcilable Conflict), the following procedures will apply. A Mini-Trial pursuant to Section 9.4 (Cost Recovery/Court Ruling) or 9.5.2 (Irreconcilable Conflict Within 7(i) Process) shall be a part of the 7(i) Process, and shall be presided over by the Hearing Officer. A Mini-Trial Pursuant to 9.5.3 (Irreconcilable Conflict Outside 7(i) Process) shall not be part of a 7(i) Process, and shall be presided over by the Administrator. A Mini-Trial shall consist of the following:

1) Parties shall file statements of position that summarize their arguments regarding the issue(s) in the underlying petition. Parties with like positions should attempt to consolidate their submissions.

2) Oral presentations, not to exceed two (2) days in total, shall be scheduled before the Administrator, and such other BPA executives designated by the Administrator. The order of presentation shall be 1) the parties in opposition to the BPA Position, Recovery/Response Proposal, or BPA final action; 2) parties, if any, in support of the BPA Position, Recovery/Response Proposal, or BPA final action; and 3) rebuttal by parties in opposition. Parties' presentations may consist of testimony, oral argument, or a combination of both. The Administrator may ask any questions or engage in any discussion with any of the participating parties that he or she deems appropriate.

3) Within 15 Business Days of the oral presentations, the Administrator shall provide a written statement that BPA maintains, modifies, or withdraws the BPA Position or Recovery/Response Proposal; or whether the BPA final action is in Irreconcilable Conflict with the PRDM. The Administrator shall summarize the basis for his or her decision. In a Mini-Trial pursuant to 9.4 (Cost Recovery/Court Ruling) or 9.5.2 (Irreconcilable Conflict Within 7(i) Process), the Administrator retains the ability to reach a different final decision at the conclusion of the 7(i) Process in the Administrator's Record of Decision.

4) In a Mini-Trial pursuant to 9.5.2 (Irreconcilable Conflict Within 7(i) Process), the Administrator may decide the BPA Position:

   A) is not in Irreconcilable Conflict with the PRDM;

   B) is in Irreconcilable Conflict with the PRDM, but BPA is now proposing to revise the PRDM consistent with Section 9.3.3 (Unintended Consequence that affects others); or

   C) is in Irreconcilable Conflict with the PRDM, but BPA is now proposing to revise the PRDM consistent with Section 9.4 (Cost Recovery/Court Ruling).

   D) is in Irreconcilable Conflict with the PRDM, and BPA is withdrawing the BPA Position or Recovery/Response Proposal.

The Customer petition opposing the BPA Position forecloses revisions under Section 9.2 (Improvement/Enhancement) and revisions under Section 9.3.2 (Unintended Consequences that do not affect others). Under Subsection B), the Administrator's decision will be accompanied by the notice required in Section 9.3.3.

Under Subsection C), the Administrator's decision will, to the extent practicable, be accompanied by the report in Section 9.4.2.1. Consistent with Section 9.4.2.2, Customers will have 10 Business Days following the Administrator's decision to petition for a Mini-Trial regarding whether BPA's Response/Recovery Proposal is necessary to ensure cost recovery or respond to a court ruling as provided for in Section 9.4.1, and/or whether the Response/Recovery Proposal is unreasonably disproportionate to what is needed to comply with the court order or to ensure cost recovery, compared to the alternative proposal(s), if any, offered by the customer(s).

5) A Mini-Trial pursuant to 9.4 (Cost Recovery/Court Ruling) or 9.5.2 (Irreconcilable Conflict Within 7(i) Process) provides an opportunity for customers to directly address the Administrator early in the 7(i) Process, but does not limit the positions BPA or parties may take during the 7(i) Process. The BPA Position, Recovery/Response Proposal, or Unintended Consequence Proposal resulting from the Mini-Trial will be considered in the normal course through the 7(i) Process with a decision in the Administrator's Record of Decision.

6) In a Mini-Trial pursuant to 9.5.3 (Irreconcilable Conflict Outside 7(i) Process), if the Administrator determines the BPA final action is in Irreconcilable Conflict with the PRDM, BPA will take all practicable steps to revoke the BPA final action. BPA may seek to revise the PRDM using the procedures in this Chapter 9. In no event shall the BPA final action, any decision made pursuant to this Section 9.6, or any action by BPA pursuant to such decision be construed to provide a basis for a claim of damages; liability for loss of profits; or special, incidental, or consequential damages.