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

2029 PUBLIC RATE DESIGN METHODOLOGY

~~*Draft 1*~~

(Redlines reflect all changes from Draft 1 to Initial Proposal)

BP-26-E-BPA-01

November 2024

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FIGURES

~~**ATTACHMENTS** (not included with First 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 beginning FY 2029-30 to develop the Section 7(b) rate for the general requirements of Publics with Contract High Water Mark (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 CHWM 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 CHWM 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 Design) 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 will be effective October 1, 2028, and will 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~~Section 2.2 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 the Allocated Tiered Cost ~~Tables~~Table (Table 2-1) established for each rate pool. The Cost Pools on the Allocated Tiered 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~~4.1.

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.

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.~~<u>Federal Columbia River Power System (FCRPS).</u>

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~~<u>As partial consideration for</u> this long-term commitment, and ~~potential future~~<u>the</u> long-term commitments<u> in the CHWM Contract</u> incorporating the PRDM, the revenues and costs associated with the sales of secondary energy will be treated in ~~a manner that recognizes BPA's long-standing treatment of these revenues. Specifically~~<u>the following manner</u>:

    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.

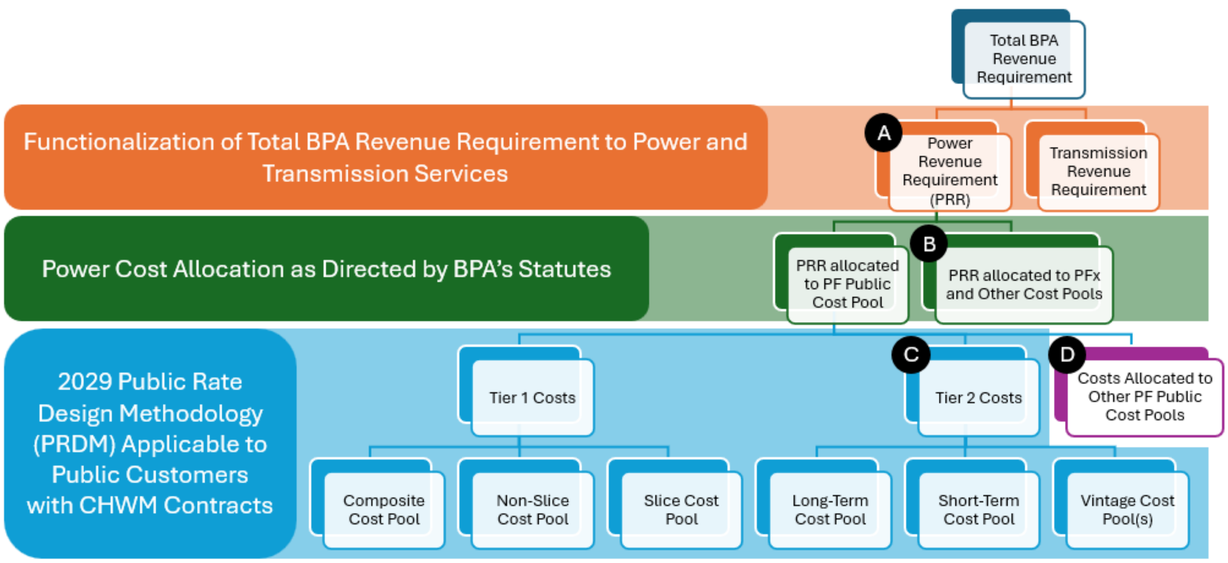
2.2 Cost Allocation Method and Allocated Tiered Cost

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~~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 2-1 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~~1.2 and 2.2.~~3~~1.3. 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~~Product. If, during the term of CHWM Contracts (including potential future contracts ~~applicable to~~that incorporate 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 Tier 1 Non-Slice ~~Tier 1~~ capacity acquisitions~~,~~ (*see* Section 3.5~~. The~~). Except as otherwise provided in Section 2.4, 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 2-1, Section D, are ~~RSS~~Support Services 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~~,~~-1 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 2-1 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~~Consequently, 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~~operations, or other decision causes a portion of the advanced sale of secondary energy associated with the Slice Product to otherwise be credited to the Non-Slice Cost Pool or when a condition exists that causes revenue to be allocated to the Non-Slice Cost Pool when a reallocation to the Composite Cost Pool would be more appropriate.

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~~any Tier 1 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.

4) If BPA determines in a 7(i) Process that it must reallocate costs to a Tier 1 Cost Pool that would otherwise be allocated to any Tier 2 Cost Pool, the presumption will be that such costs are to be allocated to the Composite Cost Pool unless it is determined in the 7(i) Process that the costs should be allocated to another Tier 1 Cost Pool based on the allocation principles in Section 2.1.

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 Charge for costs and 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 Charge 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.

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 provide Slice customers a preliminary estimate of the Slice True-Up Charge before completion of BPA's financial audit for each Fiscal Year. BPA will notify Slice customers of their Slice True-Up Charge that is calculated after audited actual financial data are available. ~~Composite Cost Pool~~The Slice True-Up Charge is 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.

2.8 Slice True-Up Composite Cost Pool Charge

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

~~2.7.1~~2.8.1 Slice True-Up Composite Cost Pool ~~Slice True-Up~~ Billing Determinant

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

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

Where:

$STUcomp_{BD}$ = A Slice customer's annual Slice True-Up Composite Cost Pool ~~Slice True-Up billing determinant~~Billing Determinant in kWh applicable to the Slice True-Up Composite Cost Pool ~~True-Up~~ Rate in mills/kWh in a Fiscal Year

Slice% = A customer's Slice percentage in that Fiscal Year

$\sum CHWM$ = sum of all customer CHWMs in that Fiscal Year

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

~~2.7.2~~2.8.2 Slice True-Up Composite Cost Pool ~~Slice True-Up~~ Rate

The Slice True-Up 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~~This difference ~~will~~is then ~~be~~ divided by the total amount of actual Tier 1 MWhs sold in the same Fiscal Year at ~~PF~~ Tier 1 rates, as adjusted by the Tier 1 Marginal Energy True-Up, to calculate the mills/kWh Slice True-Up Composite Cost Pool Rate.

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

Where:

$STUcomp_R$ = the Slice True-Up Composite Cost Pool ~~Slice True-Up~~ Rate in mills/kWh applicable to a Slice customer's kWh Composite Cost Pool Slice True-Up ~~billing determinant~~Billing Determinant in a Fiscal Year

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~~in the applicable Fiscal ~~Years~~Year of the Rate Period allocated to the Composite Cost Pool

$\sum CHWM$ = sum of all customer CHWMs in that Fiscal Year

~~*UnusedCHWM* = The~~*UCHWM* = 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 Slice True-Up Composite Cost Pool ~~True-Up~~Charge, the Firm Surplus and Secondary ~~Credit~~Adjustment (from Unused ~~Contract High Water Mark (~~CHWM~~))~~) line item in Table 2-1 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 Slice True-Up Composite ~~Customer~~Cost Pool 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~~Adjustment (from Unused ~~Contract High Water Mark (~~CHWM~~))~~) line item to calculate the actual Firm Surplus and Secondary ~~Credit~~Adjustment (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~~credit line items in Table 2-1, 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~~any amount ~~in a Fiscal Year~~ by which BPA's actual cash requirements exceed the total actual non-cash expenses in the Composite Cost Pool~~.~~ in a given Fiscal Year. 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.

~~2.7.3~~2.8.3 Slice True-Up Slice Cost Pool ~~True-Up~~ Charge

The annual Slice True-Up Slice Cost Pool 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 step 1 above by each customer's Slice Percentage pursuant to Exhibit K (or its replacement) of the Slice Contract divided by the sum of all Slice Percentages for that Fiscal Year pursuant to Exhibit ~~K~~ K (or its replacement) of the Slice Contract. The dollar amount calculated, which may be positive or negative, constitutes the Slice True-Up Slice Cost Pool Charge for the Slice Cost Pool.

~~2.7.4~~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 Charge, BPA may make an interim allocation of New Expenses or New Credits for which categories do not exist on Table 2-1. 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 Charge, 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 Slice True-Up 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 Charge, for purposes of all Slice True-Up Charge 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 Charge will be determined in each 7(i) Process.

~~2.7.5~~2.8.5 Slice True-Up Charge Settlement

~~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~~Appendix B.

~~2.7.6~~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~~Appendix B to this PRDM.

~~2.8~~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~~ *(Blackened row indicates that item is wholly assigned to another Cost Pool.)*

A. Composite Cost Pool

	A	B	C	D	E	F
	COSTS AND RATE ADJUSTMENTS	Year 1 Forecast	Actual Data	Year 2 Forecast	Actual Data	Total Rate Period
1	**COMPOSITE COST**					
2	**Operating Expenses**					
3	**Power System Generation Resources**					
4	**Operating Generation**					
5	COLUMBIA GENERATING STATION (WNP-2)					
6	BUREAU OF RECLAMATION					
7	CORPS OF ENGINEERS					
8	CRFM STUDIES					
9	LONG-TERM CONTRACT GENERATING PROJECTS					
10	**Sub-Total**					
11	**Operating Generation Settlement Payment and Other Payments**					
12	COLVILLE GENERATION SETTLEMENT					
13	SPOKANE LEGISLATION PAYMENT					
14	**Sub-Total**					
15	**Non-Operating Generation**					
16	TROJAN DECOMMISSIONING					
17	WNP-1&3 DECOMMISSIONING					
18	**Sub-Total**					
19	**Gross Contracted Power Purchases**					
20	PNCA HEADWATER BENEFITS					
21	OTHER POWER PURCHASES (Designated Obligations or Purchases)					
22	HEDGING/MITIGATION (NON-SLICE COST)					
23	OTHER POWER PURCHASES (NON-SLICE COST)					
24	**Sub-Total**					
25	**Bookout Adjustment to Power Purchases (omit)**					
26	**Augmentation Power Purchases (omit - calculated below)**					
27	AUGMENTATION POWER PURCHASES					
28	**Sub-Total**					
29	**Exchanges and Settlements**					
30	RESIDENTIAL EXCHANGE PROGRAM (REP)					
31	OTHER SETTLEMENTS					
32	**Sub-Total**					
33	**Renewable Generation**					
34	RENEWABLES (excludes KIII)					
35	**Sub-Total**					
36	**Generation Conservation**					
37	CONSERVATION ACQUISITION					
38	CONSERVATION INFRASCTRUCTURE					
39	LOW INCOME WEATHERIZATION & TRIBAL					
40	ENERGY EFFICIENCY DEVELOPMENT					
41	DISTRIBUTED ENERGY RESOURCES					
42	LEGACY					
43	MARKET TRANSFORMATION					
44	**Sub-Total**					
45	**Power System Generation Sub-Total**					
46						
47	**Power Non-Generation Operations**					
48	**Power Services System Operations**					
49	EFFICIENCIES PROGRAM					
50	INFORMATION TECHNOLOGY					
51	GENERATION PROJECT COORDINATION					
52	ASSET MGMT ENTERPRISE SVCS					
53	SLICE IMPLEMENTATION (SLICE COST)					
54	**Sub-Total**					
55	**Power Services Scheduling**					
56	OPERATIONS SCHEDULING					

	A	B	C	D	E	F
	COSTS AND RATE ADJUSTMENTS	Year 1 Forecast	Actual Data	Year 2 Forecast	Actual Data	Total Rate Period
57	OPERATIONS PLANNING	-	-	-	-	-
58	**Sub-Total**	-	-	-	-	-
59	**Power Services Marketing and Business Support**	-	-	-	-	-
60	GRID MOD	-	-	-	-	-
61	EIM INTERNAL SUPPORT	-	-	-	-	-
62	POWER INTERNAL SUPPORT	-	-	-	-	-
63	COMMERCIAL ENTERPRISE SVCS	-	-	-	-	-
64	OPERATIONS ENTERPRISE SVCS	-	-	-	-	-
65	POWER R&D	-	-	-	-	-
66	SALES & SUPPORT	-	-	-	-	-
67	STRATEGY, FINANCE & RISK MGMT (REP support costs included here)	-	-	-	-	-
68	EXECUTIVE AND ADMINISTRATIVE SERVICES (REP support costs included here)	-	-	-	-	-
69	CONSERVATION SUPPORT	-	-	-	-	-
70	**Sub-Total**	-	-	-	-	-
71	**Power Non-Generation Operations Sub-Total**	-	-	-	-	-
72	**Power Services Transmission Acquisition and Ancillary Services**	-	-	-	-	-
73	TRANSMISSION and ANCILLARY Services - System Obligations	-	-	-	-	-
74	3RD PARTY GTA WHEELING	-	-	-	-	-
75	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)	-	-	-	-	-
76	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Non-Slice Cost)	[redacted]				
77	TRANS ACQ GENERATION INTEGRATION	-	-	-	-	-
78	EESC CHARGES (Composite)	-	-	-	-	-
79	TELEMETERING/EQUIP REPLACEMT	-	-	-	-	-
80	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**	-	-	-	-	-
81	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**	-	-	-	-	-
82	**Fish & Wildlife**	-	-	-	-	-
83	**USF&W Lower Snake Hatcheries**	-	-	-	-	-
84	**Planning Council**	-	-	-	-	-
85	**Fish & Wildlife RDC Funds**	-	-	-	-	-
86	**Lower Snake Hatcheries RDC Funds**	-	-	-	-	-
87	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	-	-	-	-	-
88	**BPA Internal Support**	-	-	-	-	-
89	**Additional Post-Retirement Contribution**	-	-	-	-	-
90	**Agency Services G&A (excludes direct project support)**	-	-	-	-	-
91	**BPA Internal Support Sub-Total**	-	-	-	-	-
92	**Bad Debt Expense (Composite Cost)**	-	-	-	-	-
93	**Bad Debt Expense (Non-Slice Cost)**	[redacted]				
94	**Other Income, Expenses, Adjustments**	-	-	-	-	-
95	**Depreciation (Composite Cost)**	-	-	-	-	-
96	**Depreciation (Non-Slice Cost)**	[redacted]				
97	**Amortization**	-	-	-	-	-
98	**Accretion (CGS)**	-	-	-	-	-
99	**Total Operating Expenses**	-	-	-	-	-
100		-	-	-	-	-
101	**Other Expenses and (Income)**	-	-	-	-	-
102	Net Interest Expense	-	-	-	-	-
103	LDD	-	-	-	-	-
104	Irrigation Rate Discount Costs	-	-	-	-	-
105	Revenues, PRDM Rate Impact Credit, Mitigation (RIC-M)					
106	Costs, PRDM Rate Impact Credit, Mitigation (RIC-M)					
107	FPS (Surplus)/Shortfall					
108	7(c)(2) Delta Allocation					
109	7(b)(2) / 7(b)(3) Protection Amount					
110	7(b)(2) Industrial Adjustment					
111	**Sub-Total**					
112	**Total Expenses**	-	-	-	-	-
113		-	-	-	-	-
114	**Revenue Credits**	-	-	-	-	-
115	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	-	-	-	-	-
116	Downstream Benefits and Pumping Power revenues	-	-	-	-	-
117	4(h)(10)(c) credit	-	-	-	-	-

	A	B	C	D	E	F
	COSTS AND RATE ADJUSTMENTS	Year 1 Forecast	Actual Data	Year 2 Forecast	Actual Data	Total Rate Period
118	PRSC Net Credit (Composite)					
119	Colville and Spokane Settlements					
120	Energy Efficiency Revenues					
121	PF Load Forecast Deviation Liquidated Damages					
122	Miscellaneous revenues					
123	Renewable Energy Certificates					
124	Net Revenues from other Designated BPA System Obligations (Upper Baker)					
125	RSS Revenues					
126	Firm Surplus and Secondary Adjustment (from Unused RHWM)					
127	Balancing Augmentation Adjustment					
128	Transmission Loss Adjustment					
129	Tier 2 Rate Adjustment					
130	NR Revenues					
131	**Total Revenue Credits**					
132						
133	**Augmentation Costs**					
134	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)					
135	Augmentation Purchases					
136	**Total Augmentation Costs**					
137						
138	**DSI Revenue Credit**					
139	Revenues 12 aMW @ IP rate					
140	**Total DSI revenues**					
141						
142	**Minimum Required Net Revenue Calculation**					
143	Principal Payment of Fed Debt for Power					
144	Repayment of Non-Federal Obligations (EN Line of Credit)					
145	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls)					
146	Irrigation assistance					
147	**Sub-Total**					
148	Depreciation					
149	Amortization					
150	Accretion					
151	Capitalization Adjustment					
152	Amortization of Refinancing Premiums/Discounts (MRNR - Reverse Sign)					
153	Amortization of Cost of Issuance (MRNR-reverse sign)					
154	Cash freed up by DSR refinancing					
155	Gains/Losses on Extinguishment					
156	Non-Cash Expenses					
157	Prepay Revenue Credits					
158	Non-Federal Interest (Prepay)					
159	Contribution to decommissioning trust fund					
160	Gains/losses on decommissioning trust fund					
161	Interest earned on decommissioning trust fund					
162	Revenue Financing Requirement					
163	Capital Financing (RCD)					
164	Other Adjustments					
165	Payments for Litigation Stay Agreements					
166	**Sub-Total**					
167	Principal Payment of Fed Debt plus Irrigation assistance exceeds non-cash expenses					
168	Minimum Required Net Revenues					
169						
170	**Total Composite Cost**					

B. Slice Cost Pool

	A	B	C	D	E	F
	COSTS AND RATE ADJUSTMENTS	Year 1 Forecast	Actual Data	Year 2 Forecast	Actual Data	Total Rate Period
1	**SLICE COST**	-	-	-	-	-
2	Slice Implementation Expenses	-	-	-	-	-
3	Total Slice Cost	-	-	-	-	-

C. Non-Slice Cost Pool

	A	B	C	D	E	F
	COSTS AND RATE ADJUSTMENTS	Year 1 Forecast	Actual Data	Year 2 Forecast	Actual Data	Total Rate Period
1	**NON-SLICE COST**	-	-	-	-	-
2	Other Power Purchases (Balancing)	-	-	-	-	-
3	Other Power Purchases (Capacity)	-	-	-	-	-
4	Hedging/Mitigation					
5	Transmission & Ancillary Services (Non-Slice Cost)					
6	Third Party Trans & Ancillary Services					
7	Bad Debt Expense (Non-Slice Cost)					
8	Depreciation (Non-Slice Cost)					
9	Interest Earned on BPA Fund for Power					
10	Planned Net Revenues for Risk					
11	Accrual revenues (MRNR adjustment, if applicable)					
12	PRDM Rate Impact Credit, Capacity (RIC-C)					
13	PRDM Rate Impact Credit, Joint Operating Entity (RIC-J)					
14	Less Revenue Credits:					
15	Tier 1 Secondary Revenue Credit (less Secondary associated with Unused RHWM)					
16	Demand Revenue					
17	Peak Load Variance Revenue					
18	Marginal Energy True-Up Net Revenue					
19	Total Non-Slice Cost					

D. Tier 2 Cost Pool

	A	B	C	D	E	F
	COSTS AND RATE ADJUSTMENTS	Year 1 Forecast	Actual Data	Year 2 Forecast	Actual Data	Total Rate Period
1	**Tier 2 Cost (calculated for each T2 Rate)**	-	-	-	-	-
2	Acquisition Costs	-	-	-	-	-
3	BPA Overhead Costs	-	-	-	-	-
4	Support Services~~RSS~~ Adder					
5	Tier 2 Change Fee, Tier 2 Change Charge (Tier 2 Long-Term)					
6	Other costs, including risk-related, if appropriate					
7	Total Tier 2 Cost					

	Section A: Composite Cost Pool					
	Costs and Rate Adjustments	*Year 1 Forecast*	*Actual Data*	*Year 2 Forecast*	*Actual Data*	*Total Rate Period*
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)					
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**					
45						

	Section A: Composite Cost Pool (Continued)					
	Costs and Rate Adjustments	*Year 1 Forecast*	*Actual Data*	*Year 2 Forecast*	*Actual Data*	*Total Rate Period*
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						

	Section A: Composite Cost Pool (Continued)					
	Costs and Rate Adjustments	*Year 1 Forecast*	*Actual Data*	*Year 2 Forecast*	*Actual Data*	*Rate Period*
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**					
112						
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					

	***Section B:** Slice Cost Pool*					
	Costs and Rate Adjustments	*Year 1 Forecast*	*Actual Data*	*Year 2 Forecast*	*Actual Data*	*Total Rate Period*
170	SLICE IMPLEMENTATION					
171	Total Slice Cost					

	***Section C:** Non-Slice Cost Pool*					
	Costs and Rate Adjustments	*Year 1 Forecast*	*Actual Data*	*Year 2 Forecast*	*Actual Data*	*Total Rate Period*
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					

	***Section D:** Tier 2 Cost Pool (calculated for each T2 Rate)*					
	Costs and Rate Adjustments	*Year 1 Forecast*	*Actual Data*	*Year 2 Forecast*	*Actual Data*	*Total Rate Period*
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					

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~~Product. Tier 1 System Resources are the resources listed in Table 3-1, Tier 1 System Resources, 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~~the Tier 1 System 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~~

The resources listed in Table 3-1 will not be removed, and the Portion of Resource will not be decreased, for the duration of this PRDM. If there is a cessation of firm power from any such resource, the firm power output from the resource will be set to zero as determined in the 7(i) Process. The firm power from a given Tier 1 System Resource may change over time as determined in each 7(i) Process. The output for each resource and Portion of Resource listed in Table 3-1 so determined will be included in the Tier 1 Firm System Output used to determine whether any new resources, including market purchases, must be added to Table 3-1 for BPA to meet its CHWM obligations. BPA will only add new resources, including market purchases, to the resources listed in Table 3-1 to the extent BPA determines that it is necessary to meet BPA's CHWM obligations after accounting for the Tier 1 Firm System Output of the then existing Tier 1 System Resources and BPA's Designated System Obligations. Unlike Tier 1 System Resources, resources listed in Tables 3-3, 3-4, and 3-5 will include a purpose and that purpose can be changed as determined in a 7(i) Process.

3.2 System Obligations

3.2.1 Designated System Obligations

Designated System Obligations, as listed in Table 3-2, Designated System Obligations, 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 obligations or in combination, that create a firm obligation for the Tier 1 System Resources. Designated System Obligations also ~~includes~~include the portion ~~of~~(if any) of the Tier 1 System Resources that BPA uses to source generation inputs for BPA's ancillary and control area service obligations~~ that are provided from the Tier 1 System Resources~~, transmission losses, capacity for the Western Resource Adequacy Program (WRAP) (or its successor), Support Services, or other reserve obligations. 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

Customers with CHWM Contracts should have as much certainty as reasonably possible about Designated System Obligations. Accordingly, BPA will, if practicable, hold a public process before ~~entering into~~adopting a new Designated System Obligation. Where holding such a process is not practicable before ~~entering into or becoming subject to~~adopting 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: 1) in the case of new Designated System obligations, review the need and the forecast amount of such obligation; and 2) in the case of existing Designated System Obligations, 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 CHWM System, the simulated Slice capability, and to equitably allocate costs between Slice and Non-Slice rates. CHWM Modeled Augmentation is not a forecast of physical resources needed for load-resource balance. CHWM Modeled Augmentation is greater than zero when the ~~Tier 1 Firm System Output reduced for~~sum of customer annual CHWMs and the

Designated System Obligations is ~~less~~greater than the ~~sum of customer CHWMs~~Tier 1 Firm System Output.

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

where:

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

~~$T1FSO$ = Tier 1 Firm System Output~~

DSO = Designated System Obligations

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

$T1FSO$ = Tier 1 Firm System Output

CHWM Modeled Augmentation is an annual average modeled amount of power needed to meet the sum of customer CHWMs and the Designated System Obligations 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~~Product.

3.3.2 Rate Period Augmentation

Rate Period Augmentation is the forecast annual 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~~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 Tier 2 Acquisitions

BPA may make resource acquisitions (energy, capacity or a combination of both) for purposes of meeting its ~~PF load~~Tier 2 Load obligations~~ served at Tier 2 rates.~~. To the extent BPA makes these type of resource acquisitions, it will list these ~~resources~~Tier 2 Acquisitions 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~~Tables 3-1, ~~Table~~ 3-3, ~~Table~~and 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~~ and 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 3-1. TIER 1 SYSTEM RESOURCES

1	**Regulated Hydro Projects**	**Expiration**	**Portion of Resource**	**Resource Type**
2	Albeni Falls	n/a	100%	Hydro
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	100%	Hydro
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	“	“

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	100%	Nuclear
38	Dworshak/Clearwater Small Hydropower	n/a	“	Hydro
39	Fourmile Hill Geothermal	(year to year)	“	Geothermal
41	**Contract Purchases**	**Expiration**		
42	Priest Rapids CER for Canada	Treaty Entitlement Return	100%	Hydro
43	Rock Island #1 CER for Canada	Treaty Entitlement Return	“	Hydro
44	Rock Island #2 CER for Canada	Treaty Entitlement Return	“	Hydro
45	Rock Reach CER for Canada	Treaty Entitlement Return	“	Hydro
46	Wanapum CER for Canada	Treaty Entitlement Return	“	Hydro

Table 3-2. DESIGNATED SYSTEM OBLIGATIONS

1	Obligation	Contract Number	Expiration Date
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
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)

1	Obligation	Contract Number	Expiration Date
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	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	Resource Type
2	To be determined		n/a	100%	
3			n/a		
4			n/a		

Table 3-4. TIER 2 ACQUISITIONS

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

~~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~~	

~~1~~	~~Obligation~~	~~Contract Number~~	~~Expiration Date~~	~~Discretionary Contract?~~
~~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~~
~~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 Rate 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 Rate Design—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~~Rate design described in this chapter consists of ~~three~~four Core Rate Design ~~elements:~~charges: Tier 1 Energy Charges, Tier 1 Marginal Energy True-Up, Tier 1 Demand Charges, and Tier 1 Peak Load Variance Charges.

The ~~rate~~Tier 1 Rate design also includes ~~two~~ three Core Rate Design Rate Impact Credits: the RICc, the RICm, and the ~~RICm~~RICj. The RICc ensures customer's forecast BP-29 Rate Period capacity needs are charged the embedded cost of capacity. The RICm ~~helps transition customers from~~gradually transitions customers' effective rate changes under the Tiered Rate Methodology (TRM) to the PRDM ~~by tempering rate impacts~~. The RICj ~~gradually transitions~~ mitigates~~in~~ changes to Tier 1 Demand Charges particular to a JOE that took power under the TRM.

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 Tier 1 energy rates, and thereby ~~energy charges~~Tier 1 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~~Tier 1 Energy Charges be implemented.

The ~~energy charges~~Tier 1 Energy Charges will recover costs and credits allocated to the Composite, Non-Slice, and Slice Cost Pools. The Tier 1 ~~energy charges~~Energy Charges that recover costs allocated to the Composite Cost Pool apply to the Slice, Load Following, and Block ~~products~~Products. The Tier 1 ~~energy charges~~Energy Charges that recover costs and credits allocated to the Non-Slice Cost Pool apply to Load Following and Block ~~products~~Products. The Tier 1 ~~energy charges~~Energy Charges that recover costs and credits allocated to the Slice Cost Pool apply to the Slice ~~product~~Product.

4.1.1 Tier 1 Energy Charge Billing Determinants

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

- A customer's Tier 1 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~~Product.
- A customer's Firm Slice Amount will be used to calculate the Tier 1 Energy Charge Billing Determinants applicable to the Slice ~~product~~Product.

4.1.2 Tier 1 Composite ~~Tier 1~~ Energy Rates

BPA will establish Tier 1 Composite ~~Tier 1~~ Energy Rates in each 7(i) Process. ~~The~~Tier 1 Composite ~~Tier 1~~ Energy Rates are applicable to the Load Following, Block and Slice ~~products~~Products (mills/kWh). The Tier 1 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 Tier 1 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 annual average ~~annual~~ equivalent of the Tier 1 Composite ~~Tier 1~~ Energy Rate is equal to:

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

$$T1CompositeEnergyRate = \frac{CCP_F}{\Sigma T1EBD_F}$$

where:

$\cancel{CompositeTier1Rate_{ave}}$ $T1CompositeEnergyRate$ = the annual average ~~annual~~ equivalent of the Tier 1 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

$\cancel{CompositeCosts} =$ CCP_F = the forecast total ~~costs~~annual expenses and revenue credits in the applicable Fiscal Year of the Rate Period allocated to the Composite Cost Pool

$\cancel{\Sigma ForecastTier1EBD_{all}}$ = $T1EBD_F$ = sum of forecast Tier 1 Energy Billing Determinants for Load Following, Block, and Slice ~~products~~Products in kWh

4.1.3 Tier 1 Non-Slice ~~Tier 1~~ Energy Rate

BPA will establish a Tier 1 Non-Slice ~~Tier 1~~ Energy Rate in each 7(i) Process. The Tier 1 Non-Slice ~~Tier 1~~ Energy Rate is a rate applicable to the Load Following and Block ~~products~~Products (mills/kWh). The Tier 1 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 Tier 1 Non-Slice ~~Tier 1~~ Energy Rate can be a positive or negative value.

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

$$T1NonSliceEnergyRate = \frac{NSCP_F}{\Sigma T1EBD_{F.NS}}$$

where:

~~$NonSliceTier1Rate$ =~~ $T1NonSliceEnergyRate$ = Tier 1 Non-Slice ~~Tier 1~~ Energy Rate expressed in mills/kWh

~~$NonSliceCosts$ =~~ $NSCP_{F_F}$ = the forecast total ~~costs~~annual expenses and revenue credits in the applicable Fiscal Year of the Rate Period allocated to the Non-Slice Cost Pool

~~$ForecastTier1EBD_{NS}$~~=$\Sigma T1EBD_{F.NS}$= sum of forecast Tier 1 Energy Billing Determinants for Load Following and Block ~~products~~Products in kWh

4.1.4 ~~Slice~~ Tier 1 Slice Energy Rate

BPA will establish a ~~Slice~~ Tier 1 Slice Energy Rate in each 7(i) Process. The ~~Slice~~ Tier 1 Slice Energy Rate is applicable to the Slice ~~product~~Product (mills/kWh). The ~~Slice~~ Tier 1 Slice 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 Slice Energy Rate can be a positive or negative value.

$$\cancel{SliceTier1Rate = \frac{SliceCosts}{\Sigma ForecastTier1EBD_S}}$$

$$T1SliceEnergyRate = \frac{SCP_F}{\Sigma T1EBD_{F.S}}$$

where:

~~$SliceTier1Rate$ = Slice~~ $T1SliceEnergyRate$ = Tier 1 Slice Energy Rate expressed in mills/kWh

~~$SliceCosts$ =~~ SCP_F = the forecast total ~~costs~~annual expenses and revenue credits in the applicable Fiscal Year of the Rate Period allocated to the Slice Cost Pool

~~$ForecastTier1EBD_S$~~=$\Sigma T1EBD_{F.NS}$= sum of forecast Tier 1 Energy Billing Determinants for the Slice ~~product~~Product in kWh

4.2 Tier 1 Marginal Energy True-Up Charge

At the end of each Fiscal Year, BPA will calculate a Tier 1 Marginal Energy True-Up~~.~~ Charge. The Tier 1 Marginal Energy True-Up will be applicable to the Load Following, Block and Slice ~~products~~Products. The Tier 1 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 Tier 1 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 forecast directional differences between ~~PF~~ Tier 1 Rates and market prices~~.~~ ; and 5) in the case of the Slice Product, streamline, or potentially eliminate, the need for a separate Requirement Slice Output (RSO) Test under the CHWM Contract for the Slice Product by ensuring that RSO purchased by a Slice customer that is not used to serve the customer's Total Retail Load is purchased at market-based energy rates rather than at Tier 1 Rates.

The final Tier 1 Marginal Energy True-Up may be either a charge or a credit to a customer. If a charge, such charge shall be applied as a three-month charge spread equally across the three months following the month the final Tier 1 Marginal Energy True-Up Charge is determined by BPA. If a credit, BPA will pay any amounts owed to the customer in a single first-month bill credit. No interest will apply for charges or credits provided in this manner.

4.2.1 Tier 1 Marginal Energy True-Up Billing Determinant for the Load Following Product

The Tier 1 Marginal Energy True-Up Billing Determinant for the Load Following ~~product~~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 Tier 1 Actual Hourly ~~Tier 1~~ Load is less than its CHWM, then the Tier 1 Marginal Energy True-Up ~~billing determinant~~Billing Determinant is equal to:

$$METU_{BD} = Minimum\cancel{(ACHWM, CHWM - \Sigma AHT1L_{Annual})}(ACHWM, CHWM - \Sigma T1AHL_{A}) \times -1$$

where:

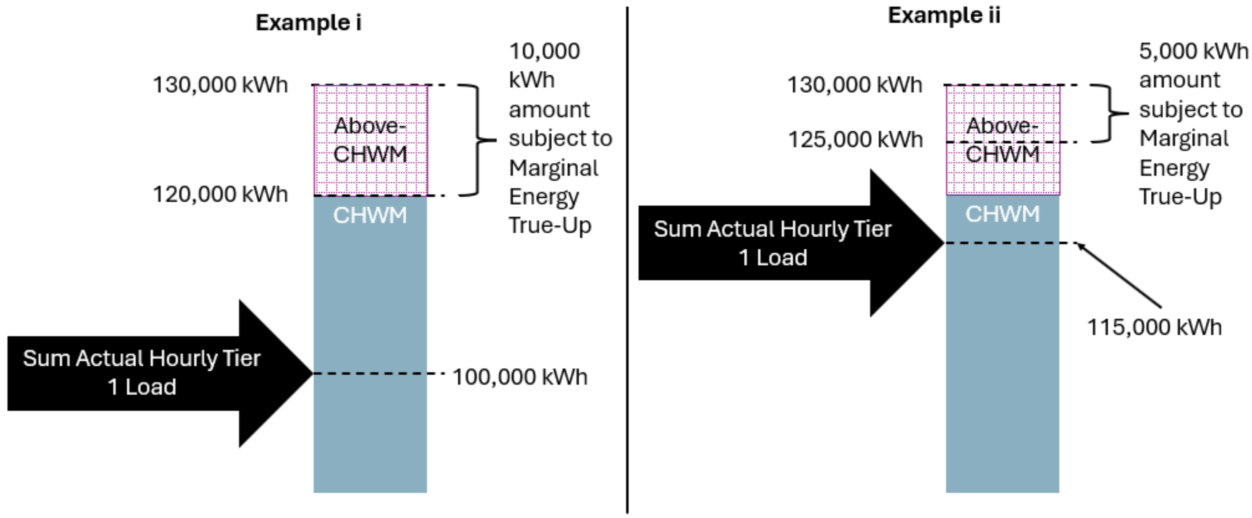
$METU_{BD}$ = Tier 1 Marginal Energy True Up Billing Determinant in kWh

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

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

$\Sigma\cancel{AHT1L_{Annual}}T1AHL_{A}$ = the customer's annual sum of Tier 1 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 Tier 1 Actual Hourly ~~Tier 1~~ Load is greater than its CHWM, then the Tier 1 Marginal Energy True-Up ~~billing determinant~~Billing Determinant is equal to:

$$METU_{BD} = \Sigma \cancel{AHT1L_{Annual}} T1AHL_A - CHWM$$

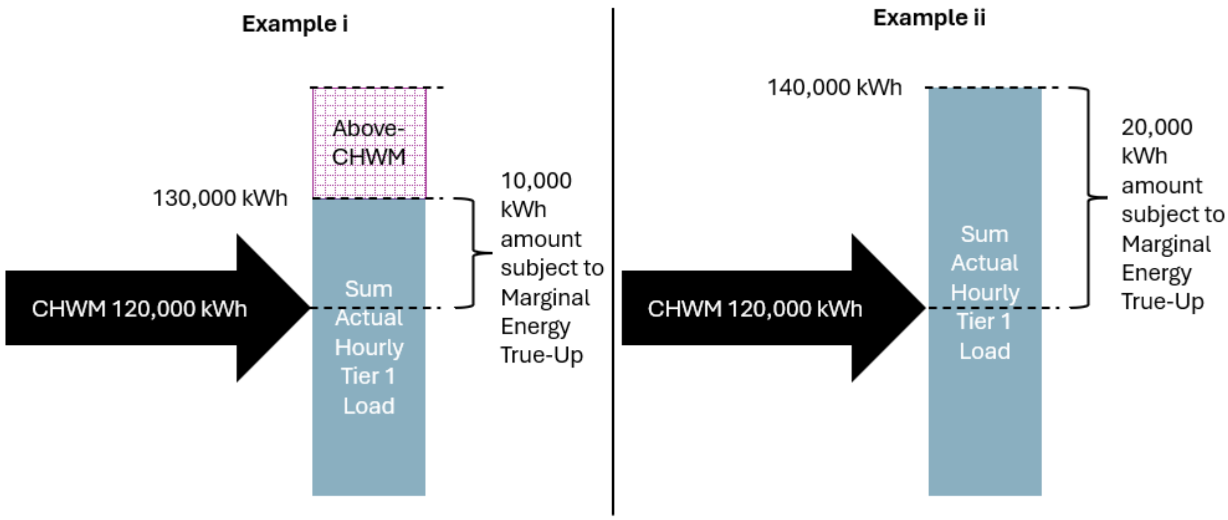
where:

$METU_{BD}$ = Tier 1 Marginal Energy True Up Billing Determinant in kWh

$\cancel{\Sigma AHT1L_{Annual}} \Sigma T1AHL_A$ = the customer's annual sum of Tier 1 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 Tier 1 Marginal Energy True-Up ~~billing determinant~~ Billing Determinant is zero.

4.2.2 Tier 1 Marginal Energy True-Up Billing Determinant for ~~the~~ Block and Slice Products

The Tier 1 Marginal Energy True-Up for ~~the~~ Block and Slice ~~products~~Products is calculated using the following equations:

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

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

where:

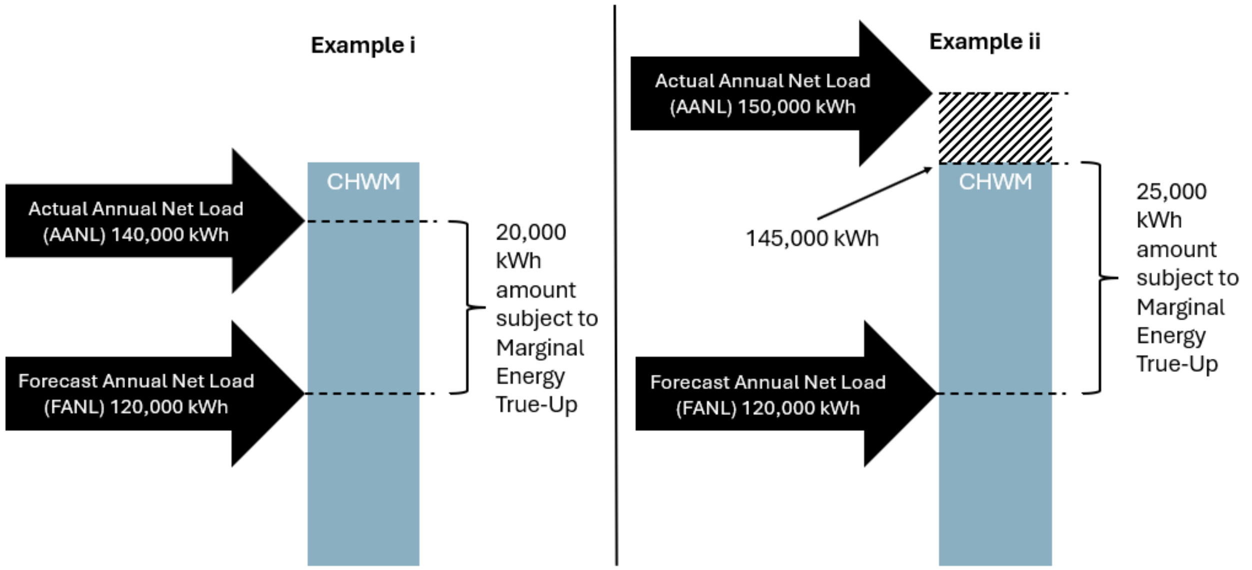
$METU_{BD}$ = Tier 1 Marginal Energy True Up Billing Determinant in kWh

$\cancel{AANL}ANL_A$ = the customer's Actual Annual Net Load in annual kWh

$\cancel{FANL}ANL_F$ = 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 Tier 1 Marginal Energy True-Up ~~billing determinant~~Billing Determinant is equal to:

$$METU_{BD} = \cancel{FANL - AANL}ANL_F - ANL_A$$

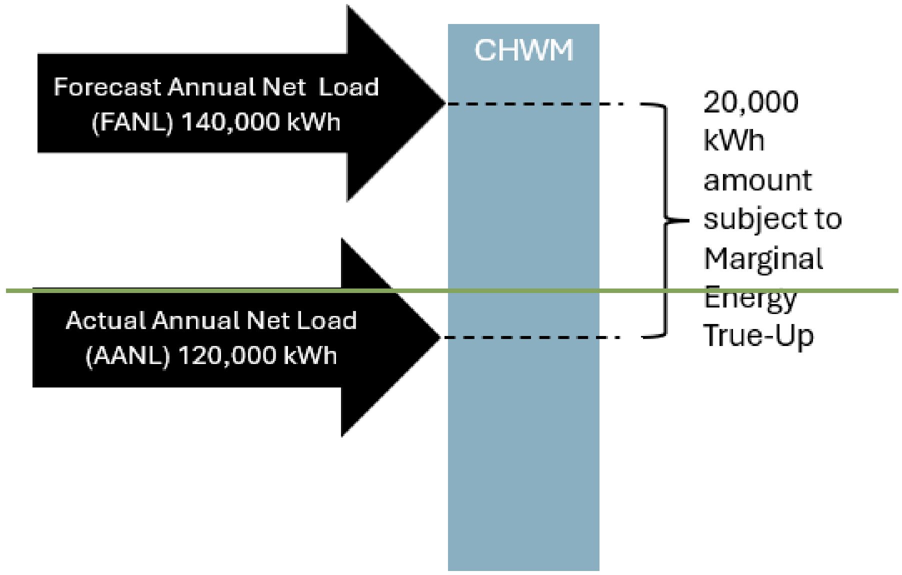
where:

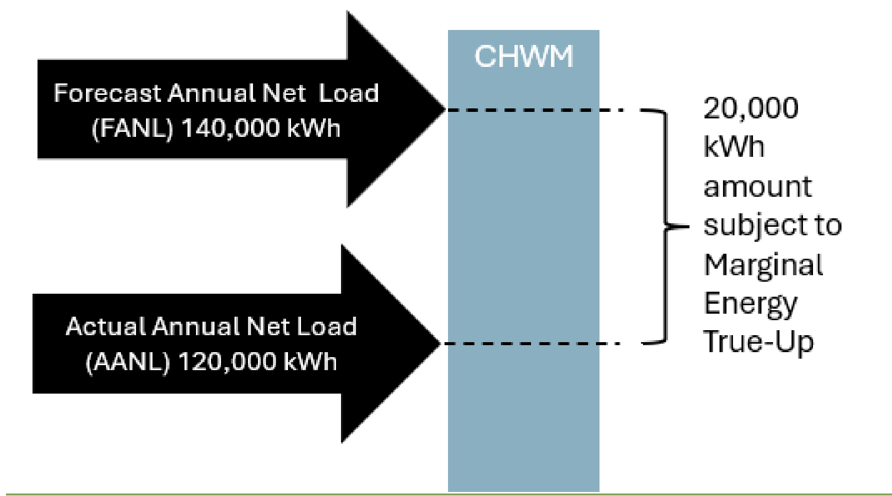
$METU_{BD}$ = Tier 1 Marginal Energy True Up Billing Determinant in kWh

$\cancel{FANL}ANL_F$ = the customer's Forecast Annual Net Load in annual kWh

$\cancel{AANL}ANL_A$ = the customer's Actual Annual Net Load in annual kWh

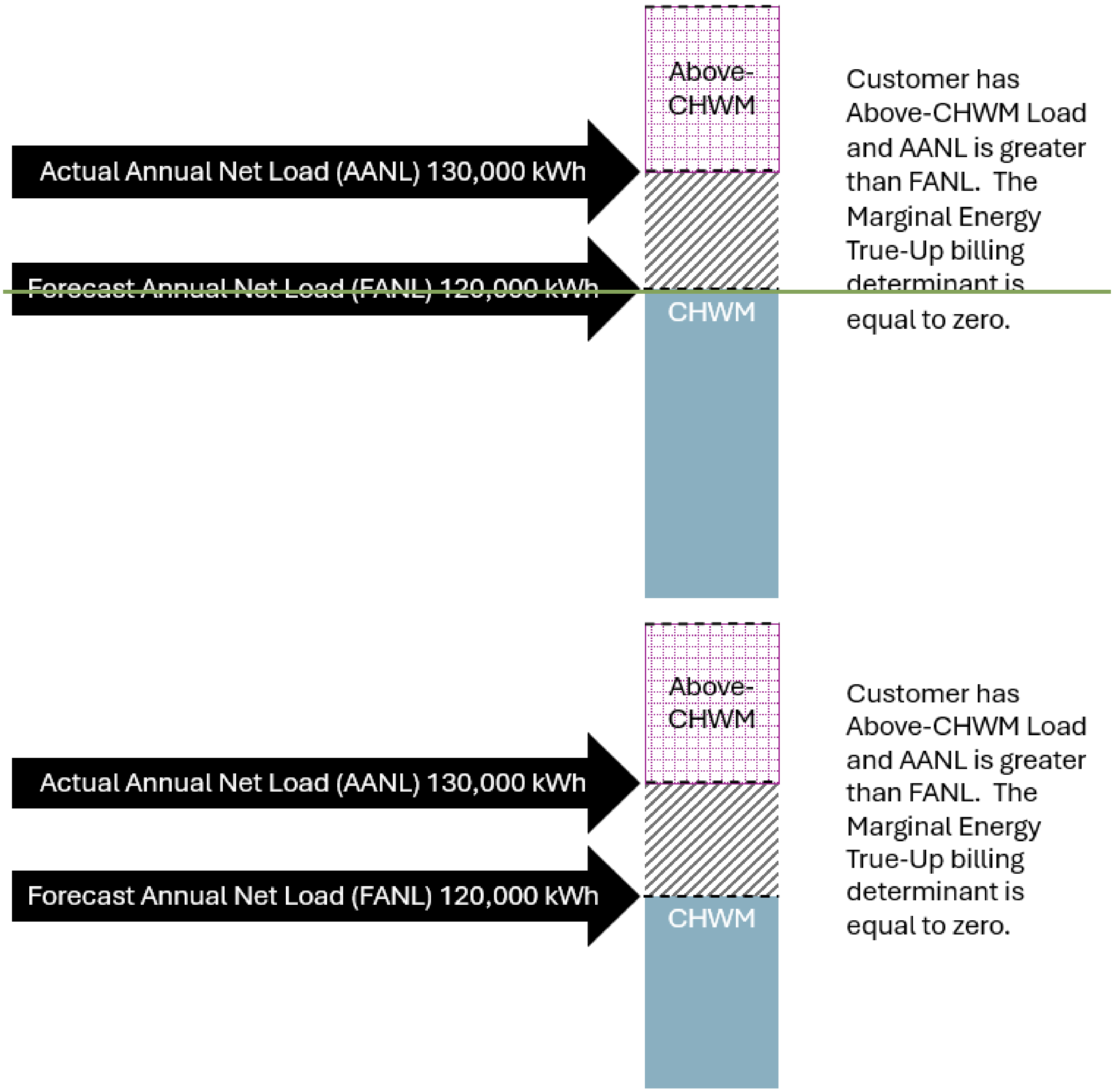
Figure 4-4. Block and Slice Condition 2, Example





Condition 3: If a Block or Slice customer has Above-~~RHWM~~ CHWM Load and an Actual Annual Net Load that is greater than or equal to its Forecast Annual Net Load, then the Tier 1 Marginal Energy True-Up ~~billing determinant~~Billing Determinant is equal to zero.

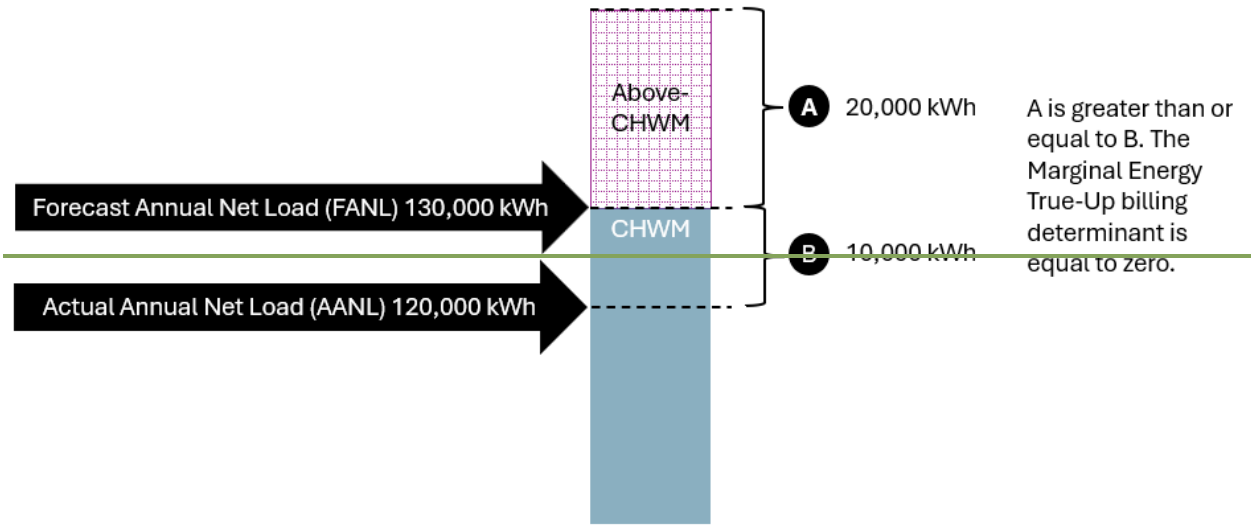
Figure 4-5. Block and Slice Condition 3. Example

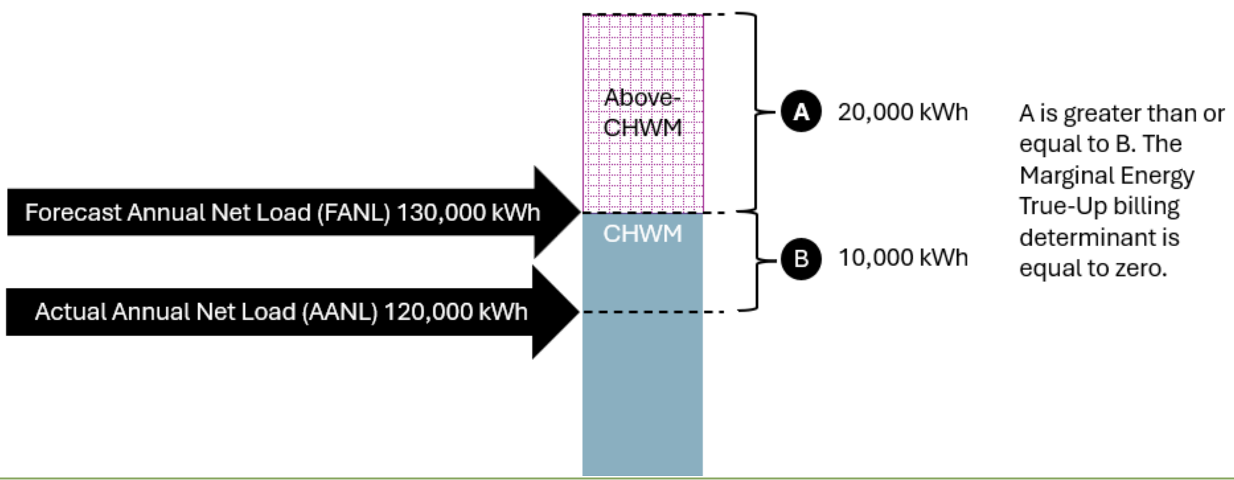


Condition 4: If a Block or Slice customer has Above-CHWM Load and an Actual Annual Net Load that is less than its Forecast Annual Net Load, then two checks will be evaluated to determine the Tier 1 Marginal Energy True-Up ~~billing determinant~~Billing Determinant.

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 Tier 1 Marginal Energy True-Up ~~billing determinant~~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 FANL minus its AANL, then the Tier 1 Marginal Energy True-Up ~~billing determinant~~Billing Determinant is equal to:

$$METU_{BD} = \cancel{FANL - AANL -} ANL_F - ANL_A - ACHWM$$

where:

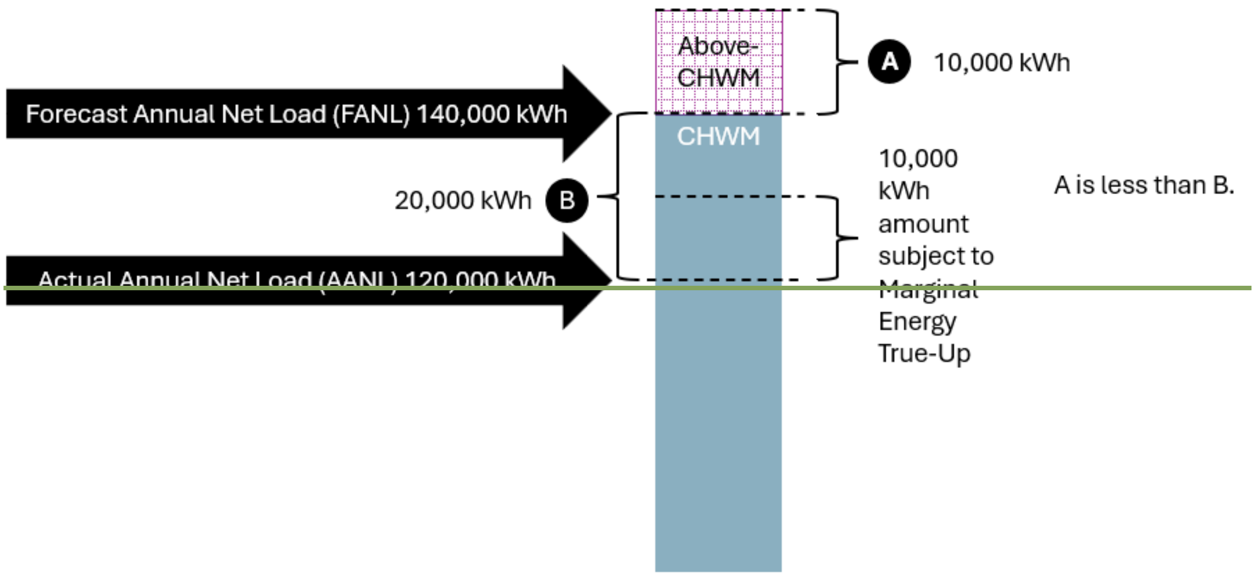
$METU_{BD}$ = Tier 1 Marginal Energy True Up Billing Determinant in kWh

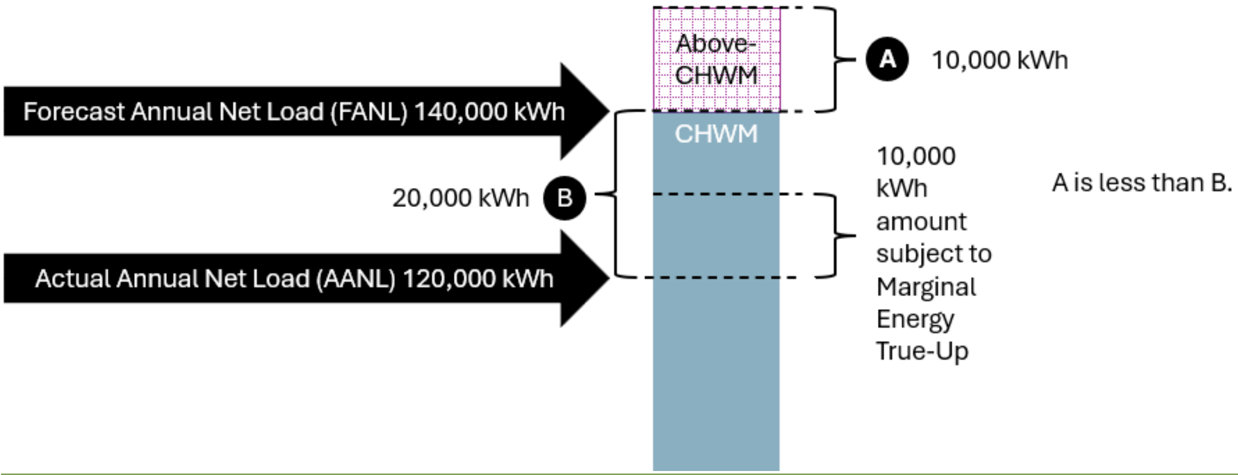
$\cancel{FANL}ANL_F$ = the customer's Forecast Annual Net Load in annual kWh

$\cancel{AANL}ANL_A$ = 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 Tier 1 Marginal Energy True-Up Rate

A customer's Tier 1 Marginal Energy True-Up Rate is the mills/kWh difference between a flat annual block of power purchased from BPA: 1) at its Tier 1 energy rates applicable to the Non-Slice ~~product~~Product, including a customer's Low Density Discount (LDD), RICc and RICm, and 2) the same amount of power had it been purchased at a market-based price. The Tier 1 Marginal Energy True-Up Rate can be negative or positive, and is specific to each customer. The market-based price will be established in each 7(i) Process. The formula BPA will use to calculate the customer's Marginal Energy True Up Rate is as follows:

$$METU_R = FB_{MKT} - \{([FB_{COMP} + NS_R] \times [1 - LDD]) + RIC_C + RIC_M\}$$

where:

$METU_R$ = a customer's Tier 1 Marginal Energy True Up Rate expressed in mills/kWh for a Fiscal Year

FB_{MKT} = the mills/kWh market price of a flat annual block of power as established in each 7(i) Process

FB_{COMP} = ~~the~~ mills/kWh cost of a flat annual block of power purchased at BPA's Tier 1 Composite ~~Tier 1~~ Energy Rates

NS_R = the Tier 1 Non-Slice ~~Tier 1~~ Energy Rate expressed in mills/kWh for a Fiscal Year

LDD = a customer's Low Density Discount applicable to the Fiscal Year subject to the Tier 1 Marginal Energy True-Up

RIC_C = a customer's RICc for the Fiscal Year subject to the Tier 1 Marginal Energy True-Up expressed in mills/kWh

RIC_M = a customer's RICm for the Fiscal Year subject to the Tier 1 Marginal Energy True-Up expressed in mills/kWh

4.3 Tier 1 Demand Charge

~~There are 12 Demand Charges—one for each month of the year—that are designed to send a~~The Tier 1 Demand Charge sends a long-run marginal price signal to customers to ~~both~~ encourage the efficient use of capacity. Tier 1 Demand Charge under this Section 4.3, together with Tier 1 Peak Load Variance Charges under Section 4.4, are also designed to recover the ~~cost~~costs of BPA holding capacity to serve customer loads ~~and encourage the efficient use of capacity.~~. Forecast ~~revenue~~revenues received from the Tier 1 Demand ~~Charges~~Charge are credited to the Non-Slice Cost Pool. ~~These~~The Tier 1 Demand ~~Charges are~~Charge is applicable to the Load Following and Block ~~products.~~Products. The Tier 1 Demand Charge is calculated as the Tier 1 Demand Charge Billing Determinant multiplied by the Tier 1 Demand Rate.

4.3.1 Tier 1 Demand Charge Billing Determinant

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

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

$$T1DBD_{Mo} = T1CSP_{Mo} - T1AHL_{A.Mo}$$

where:

$\cancel{DemandBD_{Mo}}$ ~~=~~ $T1DBD_{Mo}$ = Tier 1 Demand Billing Determinant expressed in kW per month (kW/Mo)

$\cancel{CSP_{Tier1,Mo}}$ $T1CSP_{Mo}$ = Tier 1 Customer System Peak each month expressed in kW

$\cancel{AHT1L_{ave,Mo}}$ $T1AHL_{Mo}$ = customer's average Tier 1 Actual Hourly ~~Tier 1~~ Load each month expressed in akW

For a Joint Operating Entity (JOE), the calculation of the Tier 1 Demand Charge Billing Determinant will be ~~based on~~a summation of the Tier 1 Demand Charge Billing Determinant of each ~~individual~~member utility ~~member~~.

4.3.2 Tier 1 Customer System Peak

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

4.3.3 Average Tier 1 Actual Hourly ~~Tier 1~~ Load

The average Tier 1 Average Actual Hourly ~~Tier 1~~ Load is calculated as the sum of the customer's Tier 1 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 Tier 1 Demand ~~Rate~~Rates

~~The Demand Rate~~There are 12 Tier 1 Demand Rates, one for each month of the year. Tier 1 Demand Rates 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 any offsetting fixed revenue of the Marginal Capacity Resource or 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 fixed revenue or multiple uses (for example, a battery used for shaping energy and voltage support), will be used to calculate an annual Tier 1 Demand Rate and will be shaped across the 12 months to create 12 monthly Tier 1 Demand Rates. The shape of the monthly Tier 1 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 Tier 1 Demand Rate Adjustment Cap

Increases and decreases to the monthly Tier 1 Demand Rates will be limited to ~~5%~~a maximum 10 percent (upward or downward) change every two years, with the exception of the Tier 1 Demand Rates set for the BP-29 Rate Period when the first Tier 1 Demand Rates under PRDM are established.

4.3.6 Capacity Credits

See Appendix E for the overall framework for how the Existing and New Capacity Credits apply.

4.3.6.1 Existing Capacity Credit

An Existing Capacity Credit will be applied when a Load Following customer has a Dedicated Resource that is an Existing Resource that has a capacity obligation that is greater than its monthly Exhibit A amount.

The amount of the Existing Capacity Credit will be established in each 7(i) Process as described in this paragraph. The Existing Capacity Credit will be based on the embedded cost of Supplemental Operating Reserves, or its successor, adjusted to reflect the Tier 1 System Resources only, and shaped into months using each Rate Period's monthly Tier 1 Demand Rates described in this chapter. The Existing Capacity Credit may be 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 ~~New~~Existing Capacity Credit may account for other operational characteristics of the capacity that add or subtract value. Any energy provided using this capacity will be credited to the customer at ~~the applicable Composite Tier 1 Energy Rates.~~market-based rates as determined in each 7(i) Process. The use of ~~the~~ capacity will not impact the measurement of the Tier 1 Customer System Peak and Tier 1 Actual Hourly ~~Tier 1~~ Load.

4.3.6.2 New Capacity Credit

A customer can qualify for a New 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 allocation of the cost of providing the New Capacity Credit will be determined in each 7(i) Process and may be functionalized to Power, Transmission, or a partial allocation to both. When the cost is functionalized to Power's Revenue Requirement, that cost of providing the New Capacity Credit will be allocated consistent with the BPA's statutes, *see* Figure 2-1, and the principles in Section 2.1 above.

The amount of the New Capacity Credit will be established in each 7(i) Process and will be tailored to the characteristics of the capacity provided. The New Capacity Credit will be based on the marginal cost of capacity, such as the Marginal Capacity Resource as used to establish the Tier 1 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 New 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 New Capacity Credit will also be constructed with consideration of the potential impact on the Tier 1 Customer System Peak and Tier 1 Actual Hourly ~~Tier 1~~ Load to limit situations where BPA would pay the customer twice for the same capacity—once through the New Capacity Credit and again through a reduction in Tier 1 Demand and Tier 1 Energy Charge revenue—while also considering implementation ease and practicality.

4.4 Tier 1 Peak Load Variance Charge

The Tier 1 Peak Load Variance Charge(s) (PLVC), are applicable to the Load Following ~~product~~Product and to eligible Block ~~product~~Product customers ~~who~~that 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.~~P50 (50th percentile which means that

50 percent of the peak load forecast will be equal to or exceed this value) peak load forecast up to BPA's P10 peak load forecast (10th percentile which means that 10 percent of the peak load forecast will be equal to or exceed this value). Such additional capacity will be adjusted downward for the portion that is recovered through other charges, like Operating Reserves. The costs recovered through the PLVC will be established using BPA's embedded cost of Supplemental Operating Reserves, or its successor, adjusted to reflect the Tier 1 System Resources only, and shaped into months using each Rate Period's monthly Tier 1 Demand Rates. PLVC for the Load Following ~~product~~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~~The PLVC for the Load Following Product will be calculated using energy Billing Determinants expressed in kilowatthours and the rate will be expressed in a single mills/kWh. The PLVC rate design applicable to the Block Product will be established in each 7(i) Process. The specific loads to include the energy Billing Determinants and the rates used to calculate the PLVC will be established in each 7(i) Process and may be different as between the Load Following ~~product~~Product and the Block ~~product~~Product if planning, access to and use of PLVS capacity is determined to be materially different across the products~~.~~ (*i.e.*, the cost of PLVC will be set commensurate with the service provided). For example, if the Block ~~product~~Product can be used in a way that decreases load diversity and shared pool benefits or if the Block ~~product~~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~~Product will be included in Tier 1 Actual Hourly ~~Tier 1~~ Load, and will be subject to all other applicable Tier 1 rates. Energy provided through PLVS for the Block ~~product~~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~~Product within its contractually defined Block amount will be treated as Block load served at Tier 1 Rates.

4.5 Tier 1 Rate Impact Credits

The ~~rate design~~Core Rate Design includes ~~two~~three Rate Impact Credits: the Rate Impact Credit for Capacity (RICc), the Rate Impact Credit, Mitigation (RICm), and the ~~RICm.~~Rate Impact Credit for the JOE (RICj). 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~~TRM to rates in the PRDM, by tempering rate impacts over time. The RICj is a rate design mitigation tool used for transitioning a JOE (on behalf of its member) that paid rates under the TRM to the rate design under the PRDM, by tempering the Tier 1 Demand Charge 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.~~ a summation of each member's RICc and RICm. The RICj would be calculated and applied to the JOE.

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 Tier 1 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~~Products. RICc is calculated using the effective rate difference resulting from an application of the marginal ~~demand rate~~Tier 1 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 (mills/kWh) using BP-29 Rate Period forecast ~~billing determinants~~Billing Determinants applied to marginal Tier 1 Demand Rates for the subject Rate Period and ~~(~~2) the annual Tier 1 effective rate (mills/kWh) using the same BP-29 Rate Period forecast ~~billing determinants~~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 only reflect the Tier 1 System Resources ~~only~~for the BP-29 Rate Period, and shaped into months using each Rate Period's monthly Tier 1 Demand Rates.

The RICc for Block and Slice ~~product~~Product customers is calculated the same as for a Load Following customer, with the added assumption that each Block and Slice ~~product~~Product customer elected to take only the Block ~~product~~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. As an alternative, a Block or Slice Product customer can also elect, at CHWM Contract signing, to have its RICc calculated using FY 2029 Peak Net Requirement data and its FY 2029 weather-normalized loads as established through a 7(i) Process.

The formula applied to all products is as follows:

$$RIC_c = Max\left\{0, \frac{\sum_{i=1}^{12}(DemandRate_i - ECC_i)\ x\ DemandBD_i}{T1Energy_{RICc}}\right\}$$

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 Tier 1 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 Tier 1 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 marginal Tier 1 Demand Rates as prescribed in Section 4.3.4. above.

BPA may recalculate a Load Following customer's RICc for application starting in the BP-31 Rate Period if BPA determines that a customer's BP-29 Rate Period forecast Tier 1 Demand Billing Determinants in any month is more than 15 percent different (larger or smaller) than the ~~billing determinants~~Billing Determinants that would result using the customer's weather-normalized actual FY 2029 load. In such a situation, the RICc for an applicable Load Following customer would be recalculated using the formula in Section 4.5.1, but with the following changes: 1) the customer's BP-29 Rate Period forecast Tier 1 Billing Determinants ($DemandBD_i$) will be replaced with the customer's Tier 1 Billing Determinants calculated using weather-normalized actual FY 2029 load; and 2) the customer's sum of BP-29 Rate Period forecast Tier 1 energy ($T1Energy_{RICc}$) will be replaced with the customer's Tier 1 energy calculated using weather-normalized actual FY 2029 load.

A customer's RICc may also be adjusted, at BPA's sole discretion, in a 7(i) Process to account for the customer's demand response actions taken between FY 2025 and FY 2028 that can be quantifiably demonstrated by the customer to have materially changed the customer's BP-29 Rate Case forecast or its FY 2029 weather normalized loads.

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~~this section, 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 Core Rate Design charges (TRM to 2029

PRDM). The Core Rate Design charges under the TRM include: Customer Charges, Load Shaping Charges, and Tier 1 Demand Charges. The Core Rate Design charges under the PRDM include: Tier 1 Energy Charges, Tier 1 Marginal Energy True-Up, Tier 1 Demand Charge, and the Tier 1 Peak Load Variance Charge. Although the Tier 1 Marginal Energy True-Up and the Tier 1 Peak Load Variance Charge for the Block product are considered Core Rate Design elements of the PRDM, these two are not considered Rate-Design Changes considered for purposes of the RICm. 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 will also not include the Tier 1 Peak Load Variance Charge for Block customers that are either (1) not eligible to purchase or ; (2) do not elect to purchase the PLVS for the BP-29 rate period. For Block customers that are eligible and elect to purchase the PLVS for the BP-29 rate period, the RICm will be measured by assuming a PLVC that is the same as if the customer were purchasing the Load Following Product.

~~The Rate Impact Credit for Mitigation (RICm) phases in rate impacts attributed to rate design changes between the previous and current Core Rate Design charges (Tiered Rate Design (TRM) to 2029 Public Rate Design Methodology).PRDM). The Core Rate Design charges under the TRM include the: Customer Charges, the Load Shaping Charges, and theTier 1 Demand Charges. The Core Rate Design charges under the PRDM include the: Tier 1 Energy Charges, the Tier 1 Marginal Energy True-Up, Tier 1 Demand ChargesCharge, and the Tier 1 Peak Load Variance Charge. Although the Tier 1 Marginal Energy True-Up and the Tier 1 Peak Load Variance Charge for the Block product are considered Core Rate Design elements of the PRDM, these two are not considered Rate-Design Changes considered for purposes of the RICm. 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 will also not include the Tier 1 Peak Load Variance Charge for Block customers.~~

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 (*e.g.*, negative credits) is equal to the sum of the RICc credits. The BP-29 rate impact positive-cap will be 2 percent. The RICm will be phased out ~~each~~ in two-year increments after FY ~~2029~~ 2030 by adding 0.~~10~~15 mills/kWh to each customer's negative RICm until the customer's RICm is zero or above. When a customer's two-year 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 the phase out schedule materializes over ~~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-Public 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~~

4.5.3 Rate Impact Credit, JOE (RICj)

The Rate Impact Credit for the JOE (RICj) phases in rate impacts attributed solely to changes to the Tier 1 Demand Charge calculations particular to the JOE from TRM and PRDM. The RICj credits the only JOE that paid rates under the TRM and is applicable only if that JOE elects the Load Following Product. It is a stream of bill credits phased out over time with a first-year bill credit that is calibrated to mitigate the rate impacts the JOE's members would experience as a result of changing the method used to calculate the JOE's demand Billing Determinant. The cost of the RICj would be allocated to the Non-Slice Cost Pool and would not impact any customer's Tier 1 Marginal Energy True-Up Rate. The RICj would be issued on the October bill of each Fiscal Year. The annual RICj is shown in Table 4-1.

Table 4-1. RATE IMPACT CREDIT FOR THE JOE SCHEDULE

Fiscal Year	RICj Amount
2029	$1,000,000
2030	$933,333
2031	$866,667
2032	$800,000
2033	$733,333
2034	$666,667
2035	$600,000
2036	$533,333
2037	$466,667
2038	$400,000
2039	$333,333
2040	$266,667
2041	$200,000
2042	$133,333
2043	$66,667
2044	$0

4.6 Tier 1 Other Charges

BPA will limit Tier 1 Rates and Charges to those detailed in this Chapter 4. These limitations pertain to the Core Rate Design charges and credits of the ~~PF rate design, which include Tier 1 Energy Charges, Demand Charges, and PLVCs,~~PRDM and do not encompass other adjustments, charges, credits, 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 or credits 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

Except for the Core Rate Design charges defined above, the PRDM will not further sub allocate risk-related costs ~~associated with risks across its Slice and Non-Slice~~between or within products prior to September 30, ~~2044~~2041. 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~~2041, would be decided through a 7(i) Process. A proposal to change the suballocation of risk in the Tier 1 Rates after September 30, ~~2044~~2041, in a 7(i) Process, ~~shall~~will not be considered a revision to the PRDM.

~~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 there was not enough data, systems, and tools to effectively either prove or disprove the merits of the concept, and linkage to rate design at this time. BPA intends to initiate a public process in FY 2040 to FY 2041 that will be used to evaluate the need to study the merits of the concept. The public process would determine if BPA would conduct a study and, if so, the process would be used to establish the scope of the study, confirm that the necessary data is available, and determine what data BPA would use to complete the study. The study could be used to inform how BPA and customers will proceed on this topic after September 30, 2044.~~

4.8 Cashflow Considerations

Because the Tier 1 ~~rate~~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 Tier 1 Energy Charges without reshaping.

The reshaping of the Tier 1 Energy Charges will take into account the cash-flow impacts to the customer of a forecast of Tier 1 Energy Charges~~;~~, a forecast of Tier 1 Demand Charges~~;~~, and a forecast of Tier 1 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.~~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 Rate 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 Resources will not be used in a manner that subsidizes the allocated costs of Tier 2 Rate service. All Tier 2 Cost Pools will include the marginal cost of meeting resource planning requirements as well as include the marginal cost of providing any applicable Support Services.

5.1 ~~Overall~~ Tier 2 Construct

Each customer will elect, in its CHWM 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 Tier 2 Long-Term ~~Tier 2~~ Path, the Tier 2 Flexible Above-CHWM Path, or a combination of the two paths. Above-CHWM Load under the Tier 2 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 Tier 2 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 Non-Slice Rates. Forecast Firm Inventory will be used to provide service at the Tier 2 Long-Term Rate when BPA has Forecast Firm Inventory, as determined in each 7(i) Process, and the Tier 2 Long-Term Rate has an otherwise unmet power need.

5.1.1 ~~Setting~~ Tier 2 Amounts

The amount of power purchased by a customer under BPA's Tier 2 Rate Alternatives ~~is~~for each Rate Period will be established in the Above-CHWM Process consistent with each customer's Above-CHWM Load elections. The Above-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~~would have a portion of its Above-CHWM Load served under the Tier 2 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. The 0.999 aMW election would apply to the JOE and not to each of the JOE's members.

5.2 Tier 2 Cost Basis

As described in Section 2.2.1.4, 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 Tier 2 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~~Planned Net Revenues for ~~risk~~Risk (PNRR) 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 below 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~~Support Services 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)~~operations and maintenance (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~~Tier 2 and Support Services

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

5.2.3 Tier 2 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 Tier 2 Remarketing ~~of Tier 2 Amounts~~

If BPA remarkets a customer's Tier 2 purchase obligation pursuant to the CHWM Contract, then BPA will credit the proceeds to such customer (net of any remarketing costs as described in ~~Section 6.4.1) to such customer.~~the next section). 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,~~(s) used to calculate the proceeds for the remarketed energy in 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 Renewable Energy Credits (RECs) to the customer under the customer's CHWM Contract will not affect any transfer of RECs to the customer 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 CHWM 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~~BPA acquires power for the purposes of serving Tier 2 Long-Term ~~Tier 2~~ Path obligations, or 2) after July 31, 2027, whichever occurs first. The Tier 2 Change Fee will be established in each 7(i) Process and ~~shall~~will be no lower than 0.05 mills/kWh and no higher than 0.10 mills/kWh applied to the customer's Tier 1 Load amount for the ~~remaining term of~~Rate Period immediately following the ~~CHWM Contract.~~ election.

The Long-Term Tier 2 Change Charge will be based on costs BPA determines would otherwise be spread to other Tier 2 Long-Term ~~Tier 2~~ Path customers, calculated independent to 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 three year period, BPA will notify customers with a CHWM Contract at least 60 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.~~ Pursuant to the terms in the customer's CHWM Contract, a customer may elect to serve its Above-CHWM load under the Tier 2 Flexible Above-CHWM Path. Included in the Tier 2 Flexible Above-CHWM Path is the eligibility to purchase power at a Tier 2 Vintage Rate.

A Tier 2 Vintage Rate will be established when BPA acquires a Vintage Resource(s) pursuant to the terms of the customer's CHWM Contract. The Tier 2 Vintage Rate will be based on the costs of the Vintage Resource(s) along with any associated services or costs.

The applicable Tier 2 Vintage Rate determined by BPA shall be restated in the Statement of Intent as described in the CHWM Contract.

When a customer purchases power under a Tier 2 Vintage Alternative that is in excess of its then current Above-CHWM Load, BPA ~~would~~may treat such power as either: 1) ~~an advanced~~a sale of surplus power sold at a surplus rate equivalent to the applicable Tier 2 Vintage Rate 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, as determined by BPA.

~~The contract facilitating the Tier 2 Vintage Alternative~~A formula or other special rate provision will ~~establish BPA's and the customer's obligations as well as the~~be established in each 7(i) Process to address applicable credits and charges~~, such as~~ that may result when power delivery under a Tier 2 Vintage Alterative begins within a Fiscal Year and when power delivery occurs earlier or later than planned.

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 CHWM Contract~~,~~ and include multiple services ~~to integrate~~that assist in the integration of Federal and non-Federal resources with load service. ~~RSS~~Support Services are available for all specified Non-Federal Resources that Load Following customers contractually dedicate to serve their Total Retail Load (TRL~~,~~), and for specified new renewable resources Block customers contractually dedicate to serve their TRL.

~~6.1~~ Support Services include both Resource Support Services (RSS ~~Pricing Principles~~

~~RSS will be priced comparably across Load Following~~) and ~~Block products.~~Other Support Services (OSS). RSS may include, but ~~is~~are not limited to, providing ~~scheduling services, curtailment management services,~~ forced outage services, services providing additional Federal capacity to help the customer meet its contractual obligations with BPA, or services to firm up variable generation. ~~Generally speaking~~OSS may include but are not limited to scheduling services, curtailment management services, and/or market integration related services. See Appendix D for the overall framework of Support Services.

6.1 Support Services Pricing Principles

Support Services will be priced comparably across Load Following and Block Products. With one exception, the capacity component of each ~~Resource Shaping~~Support Service will be priced at a marginal cost of capacity, such as the Marginal Capacity Resource used to set the Tier 1 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.~~ Support Service. The exception to the marginal cost of capacity pricing is for contractually required Resource Support Services applied to Existing Resources. In this situation, the capacity-based fee will be calculated using BPA's embedded cost of Supplemental Operating Reserves, or its successor, adjusted to reflect the Tier 1 System Resources only.

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~~Support Services offered by BPA will be determined in each 7(i) Process. The revenue received from providing ~~RSS~~Support Services 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~~costs that are otherwise allocated to the Non-Slice Cost Pool.

6.2 Treatment for Load Following Non-Dispatchable Dedicated Resources that are Existing Resources ~~and that are~~but Not Variable Energy Resources

BPA will apply a Forced Outage Reserves Service (FORS)-based fee to all Load Following customer's Non-Dispatchable Dedicated Resources that are Existing Resources ~~and that are~~but not Variable Energy Resources. The capacity-based fee will be calculated using BPA's embedded cost of Supplemental Operating Reserves, or its successor, adjusted to reflect the Tier 1 System Resources only. The FORS-based fee allows an Existing Resource dedicated to a Load Following customer's load that is Non-Dispatchable and not a Variable Energy Resource to produce generation below its Contract Exhibit A amounts under conditions defined in the CHWM Contract (such as ~~MWh~~megawatthour limits, frequency of occurrence, qualifying events, and notice requirements) and pay a market-based rate (inclusive of potential upward adjustments and other costs), as established in each 7(i) Process.

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

6.3 Treatment for Load Following Non-Dispatchable Dedicated Resources that are Existing Resources and ~~that~~ are Variable Energy Resources

BPA will apply a capacity-based fee to all Load Following customer's Non-Dispatchable Dedicated Resources that are both Existing Resources and ~~that are~~ Variable Energy Resources. The capacity-based fee will be calculated using BPA's embedded cost of Supplemental Operating Reserves, or its successor, adjusted to reflect the Tier 1 System Resources only. The capacity-based fee allows BPA to treat the resource as a firm resource for purposes of the Tier 1 Demand Charge, as described in Section 4.3. It also allows an Existing Resource dedicated to a Load Following customer's load that is Non-Dispatchable and a Variable Energy Resource to produce generation below its Exhibit A amounts and pay a market-based rate (inclusive of potential upward adjustments and other costs), as established in each 7(i) Process.

The capacity-based fee also allows eligible resources, as defined by the CHWM Contract, to receive a market-based energy credit (inclusive of potential downward adjustments and other costs), as established in each 7(i) Process, for amounts of energy produced by the resource in excess of its Exhibit A amounts. The capacity-based fee will be calculated using BPA's embedded cost of Supplemental Operating Reserves, or its successor, adjusted to reflect the Tier 1 System Resources only.

~~The capacity-based fee will be calculated using BPA's embedded cost of Supplemental Operating Reserves, or its successor, adjusted to reflect the Tier 1 System Resources only.~~

To avoid double counting, only the Exhibit A amounts will be used for purposes of calculating ~~billing determinants~~Billing Determinants as described in Chapter 4 of this PRDM.

6.4 Treatment for Load Following Dispatchable Dedicated Resources that are Existing Resources

BPA may apply credits, charges, and require a Load Following ~~Customer~~customer to purchase ~~Resource~~ Support Services for Dispatchable Dedicated Resources that are Existing Resources. The purpose of the credits, charges, and services is to ensure, facilitate, or help a customer meet its contractual obligations with BPA, while also capturing the dispatchable energy and capacity value of the resource. A Load Following ~~Customer's~~customer's Dispatchable Dedicated Resources that are Existing Resources will come with contractual capacity-related obligations and will also be provided an Existing Capacity Credit as described in Section 4.3.6.1.

6.5 Treatment for Load Following Resources Serving Above-CHWM Load

BPA will apply credits, charges, and may require that a Load Following ~~Customer~~customer purchase ~~Resource~~ Support Services when its resources serving Above-CHWM Load are not provided in the shape of a flat annual block of power. The purpose of the credits, charges, and applicable services is to capture the value difference, both in energy and capacity, that the customer's resource serving Above-CHWM Load brings relative to a flat annual block of power.

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 1 Risk

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, Cost Recovery Adjustment Clauses (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).

7.2 Tier 2 Risk

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, and true-ups to actual costs), as appropriate.

~~7.1 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).~~

~~7.2~~7.3 Assessment of Aggregate Risk

If, after assessing and mitigating risks for each Tier 1 Cost Pool and 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~~ancillary PF rates ~~linked to Tier 1~~not otherwise described in Chapters 4 and ~~Tier 2 in addition to other Core Rate Design rates.~~5. 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 CHWM 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~~, which 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: Tier 1 Composite ~~Tier 1~~ Energy Charge, the Tier 1 Non-Slice ~~Tier 1~~ Energy Charge, ~~The Slice~~the Tier 1 Slice Energy Charge, the Tier 1 Demand Charge, and the Tier 1 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 in ~~Attachment B~~Appendix C. 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~~BP-29 Rate Period and continuing through the term of the CHWM 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 CHWM 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~~BP-29 7(i) Process, BPA will ~~apply a~~calculate the fixed IRD percentage that will remain for the term of the ~~contract.~~CHWM Contract. The IRD percentage will be set by calculating the value ~~which~~that 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~~Rates, 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 CHWM Contract will include the terms and conditions for the IRD. The CHWM 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~~kilowatts used 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~~CHWM Contract. Eligibility for new Irrigation Rate customers will be evaluated 90 calendar days after BPA issues the final PRDM ROD in 2025. Newly eligible

IRD customers' ~~Power~~CHWM Contracts will be amended to reflect the eligible ~~kWh~~kilowatthour amounts.

For a Slice customer, BPA will apply the percentage reduction to the lesser of the customer's qualifying irrigation load (~~kWh~~kilowatthours) specified in its CHWM Contract or the sum of its monthly Block purchase at Tier 1 Rates plus the monthly Firm Slice Amount. No other charges or ~~billing determinants~~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 CHWM 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~~a Residential Purchase and Sale Agreement~~,~~ (RPSA), 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~~Section 7(b)(2) trigger amounts to BPA surplus sales, including secondary energy sales under the Slice ~~product~~Product. Notwithstanding any other provisions in this PRDM, all issues pertaining to calculation of the ~~section~~Section 7(b)(2) rate test and allocation of the ~~section~~Section 7(b)(3) surcharge will be determined in the applicable 7(i) Process.

~~MOVED to Attachment B~~

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~~).~~) or 45 percent of the sum of the CHWMs.

For purposes of calculating utility count for a Customer Group or under Sections 9.2.2.2, 9.3.2.2, 9.4.2.2, 9.5.2, or 9.5.3, a JOE is counted by its component utilities.

9.1 General Provisions

9.1.1 Process Generally Applicable to Any PRDM Revision

No revision to ~~the~~this 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~~Chapter 9 when proposing revisions to the PRDM. ~~In the event that~~Should a proposed revision to the PRDM ~~has~~ not satisfied the requirements for introduction in a 7(i) Process as set out herein, then BPA shall neither propose nor adopt such proposed revision in a 7(i) Process until the applicable requirements of ~~Section~~this Chapter 9 are satisfied.

Except as provided in ~~Section~~Sections 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, including a Customer, from taking any position with BPA on any issue outside of a 7(i) Process.

9.1.2 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~~Chapter 9 that BPA cannot otherwise timely recover its costs or that the change is necessary to effectively comply with a court ruling:

1) The ~~basic Tier 1~~Core Rate ~~design~~Design described in ~~Section~~Chapter 4, consisting of the concept of three Tier 1 Energy Charges (Composite, Slice, and Non-Slice); the Tier 1 Marginal Energy True-Up~~;~~; the Tier 1 Demand Charge; the Tier 1 Peak Load Variance Charge; and Tier 1 Credits, which include the RICc, RICm (including the RICm phase-out schedule established pursuant to Section 4.5.2), and ~~RICm.~~RICj (including the RICm phase-out schedule established pursuant to Section 4.5.3).
2) The establishment of Tier 2 Rates, as set forth in Chapter 5.
3) Cost allocation principles set forth in Section 2.1.

9.1.3 Actions Not Considered to be a Revision to the PRDM

~~The~~Subject to Section 9.1.2 and the express terms of 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 or, as applicable, such components of rates issues that are identified in this PRDM ~~that are~~as 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 2-1

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~~8.4)

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~~8.2.2)

j) Revisions to MRNR treatment (*see* Section 2.~~7.1~~8.2.~~2~~3)

k) Expenses and revenue credits (*see* Section 2.~~7.3~~8.4)

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) Establishment of Tier 1 Energy Charges (*see* Section 4.1)

s) Establishment of Tier 1 Composite ~~Tier 1~~ Energy Rates (*see* Section 4.1.2)

t) Establishment of Tier 1 Non-Slice ~~Tier 1~~ Energy Rate (*see* Section 4.1.3)

u) ~~Slice~~ Establishment of Tier 1 Slice Energy Rate (*see* Section 4.1.4)

v) Establishment of Tier 1 Marginal Energy True-Up Rate (*see* Section 4.2.3)

w) Adjustments to Marginal Capacity Resource and shape of monthly Tier 1 Demand Rates (*see* Section 4.3.4)

x) Establishment of Capacity ~~Credit~~Credits (*see* Section 4.3.6)

y) Capacity planning standards, PLVC ~~billing determinants~~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~~ Section 4.5.1.2)

~~ab) RICm phase-out schedule (see Section 4.5.2)~~

~~ac~~ab) Recovery of conservation costs and rates for product and service switching (*see* Section 4.6)

~~ad~~ac) Sub-allocation of risk in Tier 1 Rates after September 30, 2041 (*see* Section 4.7)

~~ae~~ad) Forecast costs for ~~RSS~~Support Services (*see* Section 5.2.2~~.2~~)

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

~~ag~~af) Calculations for remarketed energy (*see* Section 5.3.1)

~~ah~~ag) Tier 2 Long-Term Change Fee and Charge(*see* Section 5.4.1)

~~ai~~ah) Design, pricing, and application of the ~~RSS~~Support Services rates (*see* ~~Section~~Chapter 6)

~~aj~~ai) FORS-based fee (*see* Section 6.2)

~~ak~~aj) Risk mitigation (consistent with Chapter 7)

~~al~~ak) Rates for Unanticipated Load (*see* Section 8.1)

~~am)Applicable~~al) Applicability of Low Density Discount (*see* Section 8.~~1~~2)

~~an~~am) Irrigation Rate Discount (*see* Section 8.~~2~~3)

~~ao)~~an) PF Exchange Rate treatment ~~for customers that execute non-CHWM contracts~~ (*see* Section 8.~~3.2~~4)

~~ap~~ao) Application of Sections 7(b)(2) and 7(b)(3) of the Northwest Power Act (*see* Section 8.4.3~~.3~~)

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 9.1.3 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), 9.1.2 (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 9.2.

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 for: 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 9.2.2.2 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 9.2.2.2, 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 9.1.2 (Core Provisions) or implementation of the PRDM reserved by Section 9.1.3 (Expressly Not Revisions), BPA may, in accordance with the applicable procedures of this ~~Section~~Chapter 9, propose revisions in the PRDM: 1) 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~~BPA's Provider of Choice Policy, or 2) to accommodate BPA's participation in a day-ahead market. However, nothing in this Section 9.3 constrains BPA's ability to propose revisions in the PRDM to ensure cost recovery or comply with a Court ruling that also accommodate BPA's participation in a day-ahead market; such proposals must comply with the requirements in Section 9.4.1.

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 9.3.2 apply only to revisions to the PRDM as provided for in Section 9.3.1 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~~ investor-owned utilities (IOU) or direct service industry (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 9.3.2.

9.3.2.~~2~~1 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 for: 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~~2 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 9.3.1, but not within the scope of Section 9.3.2), 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~~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 for: 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~~will 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 a 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(C~~).~~)). 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, 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.

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 or inaction, 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 or inaction. 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 or inaction is in Irreconcilable Conflict with the PRDM; and 2) such Customers oppose the BPA final action or inaction.

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 or inaction 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~~will be a part of the 7(i) Process, and ~~shall~~will be presided over by the Hearing Officer. A Mini-Trial Pursuant to 9.5.3 (Irreconcilable Conflict Outside 7(i) Process) ~~shall~~will not be part of a 7(i) Process, and ~~shall~~will be presided over by the Administrator. A Mini-Trial ~~shall~~will 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~~will be scheduled before the Administrator, and such other BPA executives designated by the Administrator.

The order of presentation ~~shall~~will be: 1) the parties in opposition to the BPA Position, Recovery/Response Proposal, or BPA final action or inaction; 2) parties, if any, in support of the BPA Position, Recovery/Response Proposal, or BPA final action or inaction; 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, unless extended by the Administrator for good cause, 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 or inaction 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~~a) is not in Irreconcilable Conflict with the PRDM~~;~~

~~B~~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~~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~~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~~In the case of "b)" (above), the Administrator's decision will be accompanied by the notice required in Section 9.3.3.

~~Under Subsection C~~In the case of "c)" (above), 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 or inaction is in Irreconcilable Conflict with the PRDM, BPA will take all ~~practicable~~necessary steps within its authority to revoke the BPA final action or inaction. BPA may seek to revise the PRDM using the procedures in this Chapter 9. In no event ~~shall~~will the BPA final

action or inaction, 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.