Draft

Tiered Rates Methodology

March 7, 2008

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1 BACKGROUND/PURPOSE/CONTEXT

This Tiered Rate Methodology (TRM) establishes a predictable and durable means by which to tier BPA's Priority Firm (PF) power rate. Specific determinations of rate levels will be made in each general rate case in a manner consistent with the TRM in the respective section 7(i) proceedings applicable during the term of this TRM. Tiered PF rates will be implemented beginning in FY 2012.

The TRM provides for a two-tiered PF rate design applicable to requirements firm power service for those customers that choose participate in the contracts that provide for tiered rate service.

Tiered rate design differentiates between the costs of service associated with the existing Federal system (Tier 1) and the cost associated with additional amounts of power needed to serve the remaining portion of customers' net requirements (Tier 2). This TRM specifies how rates will be developed that assure to the maximum extent possible that customers will be able to purchase Tier 1 power that does not include the costs of serving other customers' load growth.

Major topics covered in this TRM include:

- how to determine customer's eligibility to purchase power at Tier 1 rates (section 2);
- how to determine the amount of power charged at Tier 1 rates (section 3);
- how costs will be allocated to the PF Tier 1 and Tier 2 rates (sections 4 and 5);
- how rates for Tier 1 and Tier 2 sales will be designed (sections 6, 7, and 8); and
- how rates for resource support services will be designed (section 9).

These allocation and rate design methods will be implemented in each BPA power rate case during the term of the Regional Dialogue contracts, except under limited circumstances, as described in section 12. BPA intends to set power rates on a two-year cycle.

Rate Period High Water Marks (RHWM), determined according to this TRM (section 2.2), are the basis for separating which portion of each customer's net requirements purchase from BPA is charged Tier 1 rates and which is charged Tier 2 rates. Each customer may purchase up to its RHWM, limited by its net requirement, at Tier 1 rates. To meet its above-RHWM net requirement, a customer may either purchase Federal power or procure non-Federal power. To the extent a customer purchases Federal power, a PF Tier 2 rate will be applied to the Federal power service.

Power products are not determined in this TRM; however, a brief description of the products is attached as Attachment A to facilitate understanding of the development of rates to be applied to the products. In addition, the Regional Dialogue Guidebook: Background on Products, Rates, and Resource Support Services available to BPA's Public Utilities (Regional Dialogue Guidebook), provides descriptions to aid in understanding the TRM, contracts and products.

2 ELIGIBILITY TO PURCHASE POWER AT TIER 1 RATES

High Water Marks (HWMs) are measured in average annual megawatts and are the starting point for determining each customer's eligibility to purchase Tier 1 System Resources. BPA will limit the sum of all HWMs to the planned firm power output of the existing Federal system, using 1937 critical water to calculate the firm power, as it is currently defined for regional planning purposes, plus a limited amount of augmentation. The augmentation limits are described in section 3.2.

This section describes the functions of and processes for developing HWMs. In addition, a transition plan for FY 2012-2014 describes the initial process by which customers select their power supply to serve their load and commit to purchase an initial amount of Tier 2 power.

There are three types of HWMs that will be determined chronologically. These HWMs are each described in detail in later subsections. Generally, the timing and purpose of these HWMs are as follows:

1) **The Forecast CHWM (FHWM)** is calculated prior to contract signing and is intended to give each customer a preliminary planning tool to begin assessing its potential CHWM and how it will serve its future load.
2) **The Contract High Water Mark (CHWM)** is calculated in 2011 and sets the initial eligibility for power service priced at Tier 1 rates. The CHWM process also defines a specific amount of augmentation included in Tier 1 System Resources to serve the loads of existing publics at Tier 1 rates.
3) **The Rate Period HWM (RHWM)** is set prior to each section 7(i) rate proceeding and uses the CHWM to help define each customer's eligibility to purchase power Tier 1 rates.

The steps for developing the CHWMs are:

Step 1 – Clarify Details of HWM Calculation (section 2.1.1)

Step 2 – Forecast Individual Contract HWMs (section 2.1.2)

Step 3 – Calculate Individual HWMs with Measured FY 2010 Loads (section 2.1.3)

Step 4 – Determine Total Tier 1 System Resources Available for HWMs (section 3.1)

Step 5 – Resize Individual HWMs (section 2.1.5.2)

Step 6 – Adjust HWM Amounts to Account for Conservation Achieved (section 2.1.6)

A timeline for HWM, contract, and relevant rate determinations is included in Table 2.1.

2.1 Contract High Water Mark

2.1.1 General Overview

The customer's CHWM will be specified in the customer's contract (CHWM Contract) and will be used to define the customer's eligibility to purchase power from Tier 1 System Resources. The calculation of CHWMs is based on each customer's adjusted historical FY 2010 retail load, the amount of non-Federal resources used to serve load in FY 2010 (Existing Resources), and the amount of critical firm power available from Tier 1 System Resources.

A key principle in determining CHWMs is the equitable and transparent distribution of power costs allocated to Tier 1 System Resources among eligible customers. The cost distribution will be based on a utility customer's measured retail FY 2010 load, with adjustments for weather normalization and anomalies, net of the customer's Existing Resources. Finally, loads are adjusted to account for conservation achieved by each utility that lowers its measured FY 2010 load. The result of these calculations is a utility's CHWM. As discussed in greater detail in

following sections, this adjusted net load is the basis for the *pro rata* distribution among customers of costs for the power from Tier 1 System Resources.

Once established, customers' CHWMs will not change during the term of the contract, except as specified in the CHWM Contract. As described in section 2.2 below, the CHWM is used in setting customers' RHWMs before each general rate case.

2.1.2 Forecast CHWM Calculation

The FHWM provides information for planning purposes, but it will not be included in customers' CHWM Contracts. The FHWM will be calculated consistent with the CHWM calculation procedures described in the section 2.1.3 with modifications to account for information that will not be known until contracts are signed or until loads are measured in FY 2010. For example, a forecast of FY 2010 loads will be used rather than actual loads.

2.1.2.1 Establishing Existing Resources

The Existing Resources portion of the FHWM calculation is the same as for the CHWM determination, with exceptions for consumer-owned resources and PURPA resources, for which the relevant FY 2010 information will not be available at the time FHWMs are calculated.

2.1.2.2 Transparency of Calculations

After calculation of the FHWMs, BPA will post on its web site the FY 2012 forecast of Tier 1 System Resources and each customer's: 1) forecast FY 2010 Total Retail Load; 2) aggregate Existing Resource determinations for FY 2010; and 3) FHWM.

2.1.3 CHWM Calculation - Determining Measured 2010 Load and Adjusted 2010 Load

The process for establishing a customer's load used for CHWM determination will be as described below for the collection of load data and the methodologies used for normalization adjustments, as shown in Figure 2.3 and described below through section 2.1.3.3.

2.1.3.1 Determining Measured 2010 Load

Within the BPA Balancing Authority Area (formerly known as the "BPA control area,") BPA's metering infrastructure is capable of measuring load on an hourly basis at the Point of Delivery of BPA power to a customer. For those customers within the BPA Balancing Authority, Total Retail Load (TRL) for FY 2010 will be calculated by first aggregating the annual load measured at the customer's points of delivery, then adding the measured output of any Behind the Meter Resources. The amount of any FY 2010 wholesale power transactions made behind the meter by the customer will then be subtracted from this load amount.

Outside of the BPA Balancing Authority Area, equivalent metered, measured and verifiable Point of Delivery load data will be required from customers where BPA metering is not available. The measured Point of Delivery load amounts will be aggregated and then, as described above, will be increased for the output of Behind the Meter Resources and distribution losses, and reduced by the amount of any behind the meter wholesale sales. Regional Dialogue Contracts will require that customers make this data available to BPA.

FY 2010 customer load data will be aggregated to a monthly level for use in the temperature-based normalization as described below in section 2.1.3.3. In addition, the customer's historical monthly load data for FY 2005 – FY 2009 will also be used to weather normalize the FY 2010

load. Customers will be required to provide this historical load data in cases where BPA metering was not available.

If there are data problems with customer meter reads in FY 2010, BPA will continue current practices to fill in missing data points or bad reads for meters available to BPA. When meter readings are not available due to meter hardware failure or when data is determined to be invalid due to meter malfunction or calibration/configuration error, BPA will estimate the erroneous readings in accordance to BPA's settlement estimation procedures. This is consistent with utility best practices. Customers will be required to follow equivalent procedures in cases where meters are not directly available to BPA.

2.1.3.2 Adjusting Measured 2010 Load for Force Majeure-Type Events and Other Anomalies

The Measured 2010 Load data as developed in section 2.1.3.1 will be adjusted, if appropriate, for force majeure-type events or load or data anomalies that materially effect the accurate and equitable determination of a customer's CHWM calculation. These types of events and anomalies are described below in sections 2.1.3.2.2 and 2.1.3.2.3. This type of load data adjustment could result from a customer request or may be initiated by BPA independently. The criteria that BPA will apply to determine whether such an adjustment will be made are described in section 2.1.3.2.4. This step does not include correcting for meter errors, which is part of the load data gathering step described in section 2.1.3.1, nor does it include adjusting for the effect of abnormally hot or cold weather, which is addressed in section 2.1.3.3.2.

2.1.3.2.1 New Large Single Load Adjustment

New Large Single Loads will be removed from load for purposes of determining CHWMs. If a load included in a customer's Measured 2010 Load is determined to be an NLSL after CHWMs

are determined the customer's CHWM will be reduced by the NLSL amount. Measured load amounts will not be adjusted to account for a customer's Contracted for/Committed to (CFCT) loads for purposes of determining CHWMs.

2.1.3.2.2 Force Majeure-type Events

As used in this section, the term "force majeure-type events" is used generically to refer to events that are outside of the control of the customer and that the customer could not avoid through reasonable care. This use is distinct and separate from the use of "force majeure" in power sales contracts, which refers to events that may excuse either party from the performance of the contract.

For the purposes of determining CHWMs, certain events beyond the control of the customer may result in the customer's measured load data not being representative of its normal load. These events could cause either increases or decreases in the Measured 2010 Load that may justify an adjustment to the load data. Force majeure-type events are expected to be rare and several criteria described below would have to be met for an event to be considered as a possible force majeure-type event.

2.1.3.2.3 Load or Data Anomalies

In cases where increased Measured 2010 Load is shown to be the result of actions or practices that are outside of accepted, prudent utility standards and practices, BPA will determine whether an appropriate adjustment to the customer's Measured 2010 Load will be made. This inquiry could be initiated by BPA or through a third-party request. Notwithstanding any of the criteria below, BPA reserves the right to reduce a customer's Measured 2010 Load to account for utility actions that increase its FY 2010 loads through actions that make no economic sense outside of

attempting to establish a larger CHWM. This would include actions such as offering power at little or no cost to increase load.

2.1.3.2.4 Criteria for Adjusting Load Data for Either Force Majeure-type Events or Load/Data Anomalies

BPA will apply the following criteria when determining whether to make an adjustment to a customer's Measured 2010 Load:

1) **Material:** The effect of the event on Measured 2010 Load must be material. To qualify as material, the event must cause a distortion in load data that would result in a 10 percent increase or decrease in the customer's CHWM, had not the event occurred.

2) **Historical Load:** The load affected must be a verifiable, historical load for which three previous years of load data is obtainable. Load amounts above the average of the previous three years will not be considered. Planned load not served in FY 2010 will not qualify as a reason to adjust Measured 2010 Load. Returning historical load that was not captured in the Measured 2010 Load will be considered only if based on substantial evidence as determined in BPA's sole discretion, the load will return in FY 2011 and is expected to exist for the duration of the power sales agreement.

3) **New Load:** BPA will not consider a new consumer load that did not consume energy during the entire year an anomaly and will consider only the Measured 2010 Load of such consumers in the CHWM calculation.

4) **Discrete Recent Event:** The event affecting the Measured 2010 Load must be a discrete event that occurred in FY 2009 or FY 2010. BPA will not consider requests for load data adjustments that include the recessionary effects or the cumulative effects of several bundled events.

5) **Outside of the Customer's Control:** The effects of events arising from the act or inaction of a customer, whether intentional or not, will not be considered to qualify for a load data adjustment.

2.1.3.3 Adjusting Measured 2010 Load for Weather (Weather Normalization)

Following any adjustments for force majeure-type events and load or data anomalies, the Measured 2010 Load will be adjusted for the cumulative effect on load of atypical weather occurring through the year. Different normalization methods will be used for non-irrigation loads, such as residential loads, and for irrigation loads. Different methods are required because non-irrigation loads vary within the year primarily in response to temperature changes, while irrigation loads vary within year and year-to-year primarily in response to precipitation. This includes the differing water needs of various crops and the effect of wind on water lost to evaporation. As a result, BPA will determine the amounts of non-irrigation load and irrigation load contained in each customer's Measured 2010 Load and then weather normalize those loads separately. The weather-normalized loads will then be recombined to reach the utility's adjusted, normalized Measured 2010 Load. This is the load from which declared non-Federal resource amounts will be subtracted, as described in the next section of this document. This full process is shown in the flow charts contained in Figure 2.4a and 2.4b.

2.1.3.3.1 Non-Irrigation Load

The Measured 2010 Load will be normalized to remove the effects of abnormal weather. Unusually mild or severe weather may result in reduced or increased electrical load, primarily related to space heating or cooling. Thus, abnormal weather results in a measured load amount that is not representative of what would be considered the utility's normal load. Weather normalization is a tool to correct load data for the effect of abnormal weather.

The relationship between temperature and seasonal retail electrical load is statistically demonstrable and temperature-based weather normalization of retail electric load is a common utility practice. BPA will use temperature data obtained from the NOAA weather station nearest to a utility's POD(s) to weather normalize the load data for each utility.

2.1.3.3.2 Temperature-based Normalization

The differences between daily average and actual temperatures are used to determine cumulative levels of above- and below-average temperatures, measured in Heating Degree Days (HDD) or Cooling Degree Days (CDD). The HDD and CDD are then multiplied by weather coefficient values that result in an electric load adjustment value (in average megawatts) associated with the non-average temperature conditions. Finally, the measured base load and the HDD and CDD adjustment values are combined to obtain the weather-normalized load. This process is described in mathematical terms in Attachment C. Figure 2.2 through Figure 2.4b demonstrate a basic example of calculating HDD, CDD and the weather-adjusted load.

2.1.3.3.3 Irrigation Load Normalization

Irrigation load can vary significantly from year to year, in response to annual variations in rainfall, sunshine, wind and other factors. As a result, irrigation load will be normalized to approximate the load that would occur in an average year. BPA will use historical load-averaging to determine the irrigation normalization adjustment. BPA will calculate a 5-year average of each customer's irrigation load for years FY 2005 through FY 2010. The FY 2010 irrigation Measured Load will then be adjusted to match the customer's calculated 5-year average. BPA will quantify customer irrigation loads primarily through customer reporting. To determine irrigation load, customers will be required to submit irrigation data based on periodic

meter reads. A principal source of this data is through customer reporting via the Financial and Statistical Report (BPA Form 110). The reporting period for irrigation load data will be extended to include the months of May through September. Customers should submit this report for 2008 by December 31, 2008 and provide the annual report by December 31 of each year. For years prior to 2008, BPA will assess the irrigation data it currently has and request further data from the customer on a case-by-case basis.

2.1.4 Determining Existing Resource Amounts to Reduce 2010 Load

The non-Federal resource amounts designated for use in FY 2010 in Exhibit C of customers' Subscription contracts as of September 30, 2006, will establish the Existing Resource amounts used for the CHWM calculations, with the following specific exceptions:

1) **Renewable Resources** - the output of new renewable resources added during the term of the Subscription contracts will not be included in the calculation of CHWMs.

2) **Centralia** – contingent on the signing of CHWM Contract and final application of BPA's 5(b)9(c) Policy on the treatment of the Centralia Coal plant, the output of Centralia will not be included in the calculation of CHWMs for Seattle City Light, Tacoma Power, Snohomish PUD, and Grays Harbor PUD. Consequently, BPA will not decrement the amount of Federal power those customers can buy from BPA.

3) **Grant PUD** – Grant PUD has indicated that it will be recalling hydropower from the Priest Rapids and Wanapum dams. This will result in a redistribution of resources for Grant and the affected customers for CHWM purposes, should Grant recall the hydro resource as indicated.

4) **Raft River Annexation** – the unspecified resources associated with Raft River's service territory annexation will not be included for CHWM purposes.

5) **PURPA Resources** – The PURPA resource amounts used to calculate a customer's CHWM will be the smaller of the declared output of the resource for FY 2010 in its Subscription contract or the actual output of the resource applied to the customer's load in FY 2010.

BPA has reviewed the resource declarations in customers' Subscription contracts and has developed proposed resource amounts for each customer based on that review. In some instances, customer resource data had not been provided for FY 2010 or was defective. BPA made preliminary determinations where the specific information referenced was not readily available. Attachment B reflects the preliminary resource amount that will be used for each customer for purposes of calculating its CHWM. BPA will develop and discuss these numbers with individual customers through a process outside of the TRM process. By August 2008, after this consultation, BPA will establish the Existing Resource amounts that will be used for the CHWM calculations. BPA will update Attachment B with those updated customer resource amounts. BPA will account for factors related to this determination that were not contemplated in the Policy in a supplemental ROD to the July 2007 Regional Dialogue ROD.

Except for consumer-owned resources and PURPA resources, the determination of the Existing Resource amounts to be used for the CHWM calculation is done at the time that the FHWM is calculated.

The determination of consumer-owned generation amounts will be established at the time of contract signing for each customer. PURPA resource amounts will be the smaller of declared

amounts for FY 2010 or actual generation of that resource in FY 2010. Accordingly, the amounts of Existing Resources in Attachment B will be adjusted by the corresponding amounts of consumer-owned generation and PURPA resources.

2.1.5 Calculating Preliminary CHWMs

Following the determination of each customer's adjusted Measured 2010 Load, a preliminary CHWM is determined. The preliminary CHWM is the result of the distribution in proportion to the customer's adjusted Measured 2010 Load to the forecast FY 2012 output of Tier 1 System Resources. This process to determine preliminary CHWMs consists of the following two steps.

2.1.5.1 Determining Limited Augmentation for Existing Publics

The sum of adjusted Measured 2010 Load for all customers is compared to the forecast FY 2012 output of Tier 1 System Resources. The Tier 1 System Resource forecast process is described in section 3.1. If the cumulative adjusted Measured 2010 Load is greater than the output of Tier 1 System Resources, BPA will augment Tier 1 System Resources, as described in section 3.2.2.

The limited augmentation determined in this step will set the maximum amount of augmentation for existing publics used in the RHWM Process. The RHWM Process is described in section 2.2.1.

2.1.5.2 Scaling Adjusted Measured 2010 Loads to Tier 1 System Resources

In the second step, each customer's adjusted Measured 2010 Load amount is proportionately scaled such that the sum of the customers' adjusted Measured 2010 Load is equal to the output of Tier 1 System Resources. If the sum of the customers' adjusted Measured 2010 Load is greater than the output of Tier 1 System Resources after the limited augmentation, each customer's

adjusted Measured 2010 Load will be scaled down in proportion to the shortfall. Correspondingly, each customer's adjusted Measured 2010 Load will be scaled up in proportion to any surplus output of Tier 1 System Resources to determine a preliminary CHWM.

2.1.6 Conservation Adjustment to Determine CHWM

The final step to calculate the CHWM is adjusting the preliminary CHWMs calculated in the previous step for conservation. The conservation adjustment to the preliminary CHWM is made to minimize any disincentive for customers to undertake conservation measures during FY 2007 through FY 2010. Because conservation may reduce a customer's FY 2010 load, and consequently its CHWM, BPA will make a conservation adjustment to the FY 2010 load. Without the conservation adjustment, the preliminary CHWM determinations reflect the benefit of all conservation achieved equally among all customers, rather than considering what portion of the total conservation was achieved by each customer and what percentage of each customer's load was reduced through its respective conservation efforts. The conservation adjustment considers these factors in adjusting the preliminary CHWMs to reflect the amount of eligible conservation each customer has achieved.

For conservation to be credited toward the conservation adjustment, it must be cost-effective, verified, and achieved from FY 2007 through FY 2010 and most importantly, reduced the customer's load in FY 2010. For calculation purposes, each utility's preliminary CHWM will be credited 100 percent (1 aMW for each 1 aMW) of customer self-funded conservation savings and 75 percent (0.75 aMW for each 1 aMW) of BPA-funded savings (*i.e.*, through the Conservation Rate Credit or bilateral contracts). The preliminary CHWMs, including any conservation adjustments, are adjusted proportionately so that the sum of the CHWMs is again equal to the output of Tier 1 System Resources used in the prior scaling. The conservation adjustment

redistributes the CHWM amounts among customers but does not increase or decrease the total CHWMs. The result of this process is the final CHWM.

For specific details on implementing the conservation adjustment see Attachment D.

2.1.7 Publishing and Finalizing CHWMs

BPA will calculate each customer's CHWM according to the procedures established in this section 2.1. BPA will publish the CHWMs on its Web site. BPA will provide stakeholders with an opportunity to comment on the individual CHWMs along with adjustments that BPA determines are anomalies or force majeure-type events.

A two week public comment period will follow publication of the CHWMs. BPA will work to resolve any issues raised by the comments. BPA will republish the final CHWMs reflecting any appropriate updates or changes within two weeks of the close of comment. The finalized CHWM for each customer will be incorporated into each customer's contract. BPA's calculation of each customer's CHWM will not be subject to alternative dispute resolution.

2.1.8 CHWM for New Public Utility Customers

In addition to the CHWMs for existing publics, additional CHWMs will be created for New Publics that form after long-term contracts are executed. Additional CHWMs for New Publics are limited to 250 aMW during the term of Regional Dialogue Contracts. This section explains the details of how such CHWMs will be calculated and the associated augmentation is discussed in section 3.2.5.

Once qualified under BPA's Standards of Service, a New Public must provide a three-year binding notice before it will be eligible to purchase power with a HWM. During the intervening period, if necessary to serve load, the New Public may purchase power from BPA at rates that are established for this specific purpose. These rates will be similar to the Targeted Adjustment Charge (TAC). Details of these rates will be determined in the applicable rate cases.

2.1.8.1 CHWM for New Publics Formed from an Existing COU

A New Public that forms out of all or part of an existing consumer-owned utility will receive a share of the existing public's CHWM. Such an assignment will be proportionate to its annexed share of the existing utility's Total Retail Load, net of any Existing Resources that are either transferred to the New Public by virtue of the annexation or dedicated by the New Public to serve its load. The CHWM provided from the existing public utility will not count toward the aggregate or rate period CHWM limits for New Publics.

2.1.8.2 CHWM for New Publics Formed from an IOU

The CHWM for a New Public formed out of all or part of an investor-owned utility will be its forecast Net Requirement for the year deliveries begin, multiplied by the percentage derived by dividing the existing CHWMs by the forecast total Net Requirements plus amounts of above-CHWM load that existing customers choose to serve by applying non-Federal resources.. This ensures that new utilities do not receive greater access to Tier 1-priced power than existing customers.

2.1.8.3 Rate Case CHWM Limit for New Publics

If requests by New Publics exceed the 50 aMW rate period limit (*see* section 3.2.6), BPA will phase in CHWMs for New Publics by proportionally reducing the individual CHWM requests

from these New Publics so that the total CHWM addition for the Rate Period is capped at 50 aMW. *See* section 3.2.6. BPA will not phase in the CHWM for New Publics with a forecast Net Requirement of 10 aMW or less. This phase in exception will be limited to the first five such New Publics that would have otherwise had its CHWM reduced, but will count toward the 250 aMW overall limit for New Publics. Any amounts provided to these excepted New Publics will increase the 50 aMW limit for that rate period.

2.1.8.4 Rate Case Limit for CHWMs for New Tribal Utilities

The CHWMs for new tribal utilities can be increased for load growth and the expansion of service territory up to a total of 40 aMW. Any such amounts will increase the 50 aMW rate period limit and count towards the overall 250 aMW CHWM limit for New Publics. This new tribal exception will expire at the earlier of: 1) the end of FY 2021; or 2) when the overall 250 aMW CHWM limit for New Publics is reached. While these new tribal utility customers will not face marginal cost prices for this load growth, they are exposed to the same marginal cost risks as other customers when the amount of power available from the Tier 1 System Resources is reduced.

2.1.8.5 Phasing In CHWM Amounts for New Publics

When there are competing requests from New Publics that exceed the 50 aMW rate period limit, New Publics larger than 10 aMW will have the amount of their CHWM requests over 10 aMW phased in over subsequent rate periods. This is to ensure that access to the contract period limit of 250 aMW is spread broadly and not used solely by one large New Public. The phase-in would be 33.3 percent for the next 24 aMW and 20 percent for any remaining amounts. *See* Figure 2.5 for an example of this phase-in.

2.2 Rate Period High Water Mark

BPA will calculate a single RHWM for each customer for each two-year Rate Period beginning with the FY 2014 Rate Period. During the first (FY 2012-2013) Rate Period, BPA will not calculate a RHWM; rather, the CHWM will be used. As described in section 2.3, for the first (FY 2012-2013) Rate Period the Transition Period method will be used for determining above-RHWM load. The RHWM sets the maximum amount of Tier 1-priced power that a customer may purchase in each year of the rate period, subject to its Net Requirements. A RHWM will be calculated for each customer in a separate process, the RHWM Process, prior to each rate case and will be the same for each year of the rate period. The RHWM will be an input to the rate case, not subject to modification, and is used in setting tiered rates.

The RHWM Process will establish a RHWM for each customer using its CHWM by accounting for changes in projected amounts of firm power from Tier 1 System Resources (*e.g.*, changing fish-flow requirements, efficiency improvements to generation or loss of a generation resource). The available output of Tier 1 System Resources is determined in the RHWM Process and is an input to the RHWM calculation. An increase in the available output of Tier 1 System Resources will result in an equal decrease in the amount of augmentation for existing publics until the augmentation is zero. Thereafter, an increase in the output of Tier 1 System Resources will increase RHWMs. A decrease in the available output of Tier 1 System Resources will result in an equal increase in augmentation for existing publics, to the extent permitted by augmentation limits. Thereafter, decreases in the output of Tier 1 System Resources will result in decreased RHWMs.

A forecast of Net Requirements for the rate period is performed in the RHWM Process. Each customer's eligibility to purchase at Tier 1 rates will be limited by its Net Requirement. In some instances, a customer's forecast Net Requirement will be lower than its RHWM, so there may be

forecast unused amounts of RHWMs. In addition to the Net Requirements forecast, BPA will forecast the amount of such unused RHWM and reduce augmentation for existing publics by a corresponding amount for that rate period. Forecast unused RHWMs will be used to reduce augmentation to the maximum extent possible and thereafter the market value of the remaining unused RHWM will be credited to the Composite Customer Charge cost pool.

As described in section 7.2, the RHWM for each customer will be subtracted from its forecast Net Requirements to determine above-RHWM for each year of the Rate Period. Subject to the notice requirements in section 7.1.1, customers who have elected BPA as their provider will have their above-RHWM loads served at Tier 2 rates. A transitional method to set above-RHWM will be used for FY 2012-2014 instead of this method.

2.2.1 RHWM Calculation

Expressed as a formula, the RHWM load will be calculated for each customer as follows:

$$RHWM = \frac{CHWM}{\sum CHWM} \times T1SR$$

where:

CHWM = Contract High Water Mark

T1SR = Tier 1 System Resources

2.2.2 RHWM Timing and Transparency

The RHWM is an input to the rate case and will be developed through the separate RHWM Process prior to each rate case. *See* Timeline, Table 2.1.

The RHWM for each customer, including the determination of the available output of Tier 1 System Resources for the upcoming Rate Period will be made public through posting to BPA's web site. BPA will consider stakeholder feedback following the release of the RHWMs. BPA will then work with customers to resolve any concerns and will publish final RHWMs reflecting any updates and corrections. *See* Timeline, Table 2.1. The RHWM determinations are not subject to alternative dispute resolutions.

2.3 Transition Period Method for Setting Power Purchase Amounts at Tier 2 Rates

The first three years of the power sales contract, FY 2012-2014, will be a Transition Period prior to the full implementation of tiered rates. The key feature of the Transition Period method is above-RHWM loads will be estimated in 2009 based on forecast loads as described below. Customers will then commit to specific power purchases priced at Tier 2 rates for at least the first two years of the Transition Period or to self-supply, based on the above-RHWM load estimates.

It is important to note that CHWMs will still be calculated and used to set the RHWMs for the Transition Period. The Transition Period method estimates above-RHWM load amounts priced at Tier 2 rates but does not define the amount of power that a utility may purchase at Tier 1 rates, which will be set by the RHWM for the years of the Transition Period.

[this italicized paragraph is for context and will not appear in the Methodology]*The Transition Period method was developed to provide planning certainty for both BPA and customers regarding service to customers' above-RHWM load. This is necessary because the calculation date for the CHWM that would otherwise determine customers' initial tiered-rate purchase amounts will not occur until approximately June 2011. This date is too close to the first delivery*

of power in FY 2012 to allow each customer to make reasoned decisions whether to self-serve all or a portion of its above-RHWM load. Correspondingly, BPA cannot make informed resource acquisition decisions for Tier 2 service without timely notice of the amount of customers' above-RHWM load that it will be purchased.

In 2009, a proxy for the CHWM calculation will be used to establish customers' above-RHWM load amounts, using forecast loads and a forecast of the CHWM. To the extent that Load Following customers commit by November 1, 2009, to purchase amounts of Tier 2-priced power that turn out to be greater or less than the above-RHWM load amounts set in FY 2011 by the CHWM determination, the Load Shaping Charge of the Tier 1 rate design will function to financially align the amount of the power the customer has committed to purchase with the amount of its actual power needs. This function is further described in section 6.2, below. For customers either applying declared specific new resource amounts or committing to defined amounts of BPA load service at a Tier 2 rate for a period longer than the first rate period, resource removal and Tier 2 remarketing provisions of the tiered rate design greatly mitigate the risk of committing to defined purchase amounts for periods longer than the first rate period. As with any Tier 2-priced power purchase under the TRM, there is still some chance that the market price forecasts used as the basis for the Load Shaping Charge and the Tier 2-priced power remarketing calculations will not be exactly in line with the cost basis for the power purchased, but this is a balanced risk with possibilities of providing benefits or costs to customers. This is not just an issue for the Transition Period, however, and is discussed in sections 6.2 and 7.4, below.

2.3.1 Establishing Above-RHWM Load and FY 20012, 2013 and 2014 Loads

Each customer's above-RHWM load for the applicable year of the Transition Period will be set in 2009. Above-RHWM load is based on the difference between a forecast of each customer's Net Requirements for the Transition Period years and a forecast of each customer's CHWM. This method of establishing above-RHWM load differs from the standard CHWM-based method primarily in using forecast load data for the forecast of CHWMs rather than the actual load data used to derive the CHWMs. In addition, this method excludes the load normalization and conservation adjustment steps included in the CHWM calculation. Expressed as a formula, the above-RHWM load will be calculated for each customer as follows:

$$\textit{Above-RHWM load} = (\textit{2012, 2013, 2014 forecastTRL}_{2009}) - \textit{ForecastCHWM}_{2009}$$

2.3.1.1 Calculating the 2009 Forecast of the CHWM

As described in section 2.1.2, the FHWM has three principal elements: 1) the forecast of FY 2010 TRL; 2) the customer's "existing" non-Federal resource amounts designated for use in FY 2010; and 3) the forecast of available Tier 1 System Resources for FY 2012. While the calculation of the 2008 FHWM is distinct from the 2009 forecast of the CHWM for the Transition Period method, the principal elements are the same. The specific Existing Resource amounts from Attachment A will also be used for the forecast of the CHWM in 2009. As a result, the only different variables between FHWM and the 2009 forecast of the CHWM will be the forecast of the FY 2010 TRL and the forecast of FY 2012-2013 available output of Tier 1 System Resources. These variables will be calculated in 2009. The 2009 forecast of the CHWM will be calculated as follows for each customer:

$$2009 Forecast\ CHWM =$$

$$[\ (2010\ forecast\ TRL_{2009} - 2010\ nonFederal\ resources_{2008})$$

$$\div \Sigma(2010\ forecast\ TRL_{2009} - 2010\ nonFederal\ resources_{2008})\ ]$$

$$\times\ average\ of\ 2012,\ 2013\ T1SR_{2009}$$

2.3.2 2-Year and 3-Year Commitments

By November 1, 2009, customers will be required to commit to 1) who will serve its above-RHWM load during the Transition Period and 2) specific amounts of power priced at Tier 2 rates that each customer will purchase from BPA for at least the first two years of the Transition Period. Each customer will identify how it will serve its above-RHWM load.

Each customer will make a three-year commitment as to who will serve its established above-RHWM load for the Transition Period. Block and Block/Slice customers will establish any above-RHWM load amounts they commit to serve with power from BPA at Tier 2 rates for the entire Transition Period. However, Load Following customers are not required to establish specific amounts for the entire Transition Period. Specifically:

1) For a Block or Slice/Block customer, or a Load Following customer who chooses to set its above-RHWM purchase amounts at Tier 2 rates (such as a Vintage Tier 2 rate), purchase amounts are based on the specific commitments it elects for each of the three years of the Transition Period.
2) For a Load Following customer who selects BPA to serve all of its load, net of any Existing Resources, specific purchase amounts of Tier 2-priced power will be set for only the first two years of the Transition Period, FY 2012-2013. For this Load Following customer, the Tier 2-priced purchase commitment for FY 2014 will be determined through what will become the standard approach for "locking

down" above-RHWM amounts in the RHWM Process. At that time, it will be the amount that the Load Following customer's forecast Net Requirement for FY 2014 exceeds its RHWM set for the FY 2014-2015 rate period (after accounting for specific amounts of power at Tier 2 rates, such as Vintage Tier 2-priced power it has otherwise committed to purchase, if applicable).

3) For FY 2015 and thereafter, the standard method for determining above-RHWM commitments will apply as described in section 2.4, and will be subject to BPA's standard Notice and Commitment Periods (*see* section 7.1.1).

2.4 Determination of Tier 2-Priced Purchase Amounts after the Transition Period

Following the Transition Period, a customer's purchase amount of Tier 2-priced power is the amount its forecast Net Requirements exceeds its RHWM. This forecast is conducted in the RHWM Process and is not the annual Net Requirements determination. The customer's actual Tier 2-priced purchase amount is based on the rate alternative election that the customer has already committed.

If a customer applies non-Federal resources to serve all of its above-RHWM load, it must provide those resources in an amount that will reduce its net requirement load to no more than its RHWM. In that case, the Tier 2-priced load service from BPA for that customer would be zero.

2.5 Residential Exchange for Public Customers

[these italicized paragraphs are for context and will not appear in the Methodology]*A principal objective in tiering BPA's rates is to maintain the low-cost basis of the Tier 1 System Resources. This objective will be compromised if the costs of customer's new resources are melded with the costs of Tier 1 System Resources through the Residential Exchange Program (REP). BPA is in*

the process of modifying the Average System Cost Methodology. BPA is proposing to modify the ASC Methodology to prohibit customers that execute CHWM Contracts from including the costs of resources placed in service after September 30, 2006, in their Average System Cost (ASC) and exchanging those costs against the costs of the Federal system. This change to the ASC Methodology will support BPA's overall objective of maintaining and not diluting the value of Tier 1 System Resources by limiting a utility's ASC. Excluding resources added after September 30, 2006, will limit customer's ASCs and thereby not cause dilution of the value of Tier 1 System Resources.

The Regional Dialogue contracts with a CHWM will also provide for a prorated share of Renewable Energy Certificates (RECs) associated with specified renewable resources used to serve loads at Tier 1 rates.

A customer who wishes to participate in the REP with an ASC that contain all of its resource costs, including those costs for resources added after September 30, 2006, will be offered a Regional Dialogue Contract without provision for a CHWM sometime after December 2008. Power sold pursuant to contracts without a CHWM will face a rate design determined in the applicable rate cases during the term of the Regional Dialogue Contract. In addition, customers with contracts without a CHWM will not receive environmental attributes associated with the resources whose costs are assigned to the Tier 1 loads.

2.5.1 *REP Benefits for New Publics*

A New Public will also have a choice of a Regional Dialogue contract with a CHWM (see section 2.1), or a contract without a CHWM if it opts to retain its rights to receive full REP

benefits. Treatment of New Publics is the same as described above for existing public customers in section 2.5.

3 FEDERAL SYSTEM RESOURCES

The projected amounts of Federal system resource output, contract purchases, and contract obligations necessary for developing tiered rates will be determined in accordance with this TRM. The projected amounts assigned to each tier of service will be used in the CHWM and RHWM Processes and incorporated in the ratemaking process.

3.1 Tier 1 System Resources Used to Establish Tier 1 Rates

The Federal system resources, contract purchases, and contract obligations used to establish the quantity of power available for service at Tier 1 rates (Tier 1 System Resources) will be comprised of BPA's best estimate of the following elements: 1) Federal system hydro generation estimates for regulated and independent hydro projects that BPA markets or is contracted to market; plus 2) other Federal system resources, including non-Federally owned projects of which BPA has acquired the output; plus 3) other BPA contract purchases; less 4) other BPA contract obligations; plus 5) any augmentation to the Tier 1 System Resources (*see* section 3.2 for further details). Table 3.1 lists the resources, purchases and lists the obligations used in determining Tier 1 System Resources. The net of these Federal system resources less contract obligations will become BPA's forecast of available Tier 1 System Resources.

The estimates used in the determination of Tier 1 System Resources will be completed by August 15 of the Forecast Year and included in the RHWM Process. *See* section 3.1.5.

3.1.1 Federal System Hydro Generation Forecast

BPA markets the hydro generation from regulated and independent hydro projects. BPA will provide its best estimate of Federal system regulated and independent hydro generation included in Tier 1 System Resources.

The Federal system regulated hydro projects are owned and operated by either the U.S. Bureau of Reclamation (Reclamation) or the U.S. Army Corps of Engineers (COE). For each Rate Period, a hydroregulation study will be developed to incorporate known reservoir operating assumptions and include information from any agreed-upon operations concerning a Federal Columbia River Power System (FCRPS) Biological Opinions (BiOp). Federal system independent hydro projects are not modeled or regulated in BPA's hydroregulation study. BPA markets the power from independent hydro projects and relies on generation forecast updates that are provided by Reclamation, the COE, and other project owners.

In the event that a final BiOp for any future year is not available, BPA will make its best estimate of operations under a BiOp that BPA believes to be the most indicative of operations during the Rate Period. The regulated and independent hydro projects included as Federal hydro in Tier 1 System Resources are detailed in Table 3.1. The particular resources on Table 3.1 will not be removed nor added to for the duration of this TRM. The rate period forecast of the output of these resources may change; however the entire firm forecast output of these resources is committed as Tier 1 System Resources, except as provided in section 2.2.

3.1.2 Other Federal System Resources Forecast

Other Federal system resources forecast includes the purchased output from non-Federally owned projects or project generation directly assigned to BPA. Forecasts of output from the other Federal system generating projects are typically provided by the project's owner. For each Rate Period, BPA will provide its best estimate for other Federal system generation projects if the project owner does not provide a forecast. The other Federal system generating projects included as Tier 1 System Resources are detailed in Table 3.1. The particular contract resources

on this list will not be removed nor added to for the duration of this TRM. The forecast for the rate period output of these resources may change but the entire firm output of these resources is committed as Tier 1 System Resources, except as provided in section 2.2. If a contract for other Federal Tier 1 System Resources expires during the term of this TRM, and the contract is renewed, the contracted resource shall remain in Tier 1 System Resources. If the contract is not renewed, then the resource will not be replaced.

3.1.3 Other BPA Contract Purchases

BPA purchases power from sellers under a variety of contractual arrangements to meet Federal firm load obligations. The contracts are categorized as: 1) power purchases and resource acquisitions; 2) power or energy exchange purchases; 3) capacity purchases or capacity-for-energy exchange contracts; and 4) power purchased or assigned to BPA under the Columbia River Treaty. These other BPA contract purchases are considered firm resources that are delivered to the Federal system regardless of weather, water, or economic conditions. The other BPA contract purchases will be estimated using BPA's existing (on October 1, 2006) contract purchases available for Tier 1 System Resources. BPA's other contract purchases included as Tier 1 System Resources are detailed in Table 3.1. The particular contracts on this list will not be removed or added to for the duration of this TRM. The output of these resources may change but the entire firm output of these resources is committed as Tier 1 System Resources, except as provided in section 2.2. If a contract purchase expires during the term of this TRM, then the contract amount will be set to zero at the appropriate month of the relevant rate period. If the contract is renewed, it will not be included as a Tier 1 System Resource.

3.1.4 Other BPA Contract Obligations

There are a number of obligations that are imposed on BPA by statutes, treaties, Memoranda of Agreement, and contracts that require the generation or delivery of power, or forbearance from generating power, in order to support the operation of the FCRPS. BPA's other contract obligations (the successor to System Obligations as used in the Subscription Slice contract) include the Canadian Entitlement, Reclamation loads, exports, intra-regional transfers, real power transmission losses, and other Federal system obligations, such as, but not limited to, contracts pertaining to BPA transmission and reliability services, resource support services, contract agreements that are load obligations on the Federal system, or other estimated reductions to Federal system resources that may or may not have specific signed contracts. The Federal system contract obligations can change over time and are assumed to be served by Federal system firm resources regardless of weather, water, or economic conditions. BPA will make its best estimate of these contract obligations for the Rate Period. BPA's other contract obligations reduce Tier 1 System Resources. These obligations are detailed in Table 3.1. Obligations on this list will not be removed for the duration of this TRM. However, if there is a cessation of an obligation, the obligation amount will be set to zero at the appropriate time in the relevant rate period. Statutory and treaty obligations will continue even if the implementing contract expires. The successor contract for statutory and treaty obligations will replace the listed contract. Discretionary Obligations incurred prior to October 1, 2006, will not be replaced upon expiration. No Discretionary Obligations subsequent to October 1, 2006, will be added to this list.

3.1.5 Calculation of the Tier 1 System Resources

The forecast of the output of Tier 1 System Resources is calculated by summing the forecasts of Federal system hydro resources (section 3.1.1), other Federal system resources (section 3.1.2), and other BPA contract purchases (section 3.1.3), less forecasts of other BPA contract

obligations (section 3.1.4). The netting of forecast Federal system resources against forecast contract obligations will become BPA's forecast of the output of Tier 1 System Resources prior to augmentation. This forecast will be based on BPA's most recently published White Book, updated for known changes in river operations and/or resource availability.

The forecast of the output of Tier 1 System Resources will be completed by the August 15 of the Forecast Year for use in RHWM Process. This same resource forecast will be the basis for Tier 1 System Resources in the ensuing rate case, but may be revised for new information that becomes available after the RHWM Process. Revised resource forecasts made after August 15 will not change the results of the RHWM Process.

3.1.6 Changes to Planned Amounts Federal System Resources

The Tier 1 System Resources listed on Table 3.1 will not change for the duration of this TRM, except as noted below. While the listed Tier 1 System Resources will not change, the output of any particular resource is subject to change. If a listed resource ceases to operate, the output will be set to zero. BPA will not replace the resource; the output of Tier 1 System Resources generation will be reduced for the duration of the TRM or until the resource is available again. Modifications to the component resources and obligations of Tier 1 System Resources are limited as defined in sections 3.1.1, 3.1.2, 3.1.3, and 3.1.4.

3.2 Allocation of New Federal System Resource Acquisitions

After September 30, 2006, the costs of new Federal resource acquisitions will be allocated to cost pools on a Rate Period or longer basis. Specific cost allocation for these acquisitions could include:

- Augmentation for Existing Publics – costs allocated to Tier 1 rates in the Tier 1

Composite Customer rate;

- Augmentation for New Publics – costs allocated to Tier 1 rates in the Tier 1 Composite Customer rate;
- Balancing Power Purchases – costs allocated to non-Slice rates in the Non-Slice Customer rate;
- Tier 2 energy delivery – costs allocated to Tier 2 rates;
- Capacity for load following customer service – costs allocated to non-Slice rates in the Non-Slice Customer rate;
- Transmission Services capacity obligations – costs allocated directly to Transmission Services resulting in a reduction of BPA system obligations as defined in section 3.1.4, Other BPA Contract Obligations; and
- Tier 1 Resource Support Services (RSS) capacity obligations – costs charged to RSS purchasers with a corresponding reduction of BPA system obligations, as defined in section 3.1.4, Other BPA Contract Obligations.

3.2.1 Augmentation of Tier 1 System Resources

In each rate case, BPA will determine the appropriate amount of augmentation to be included in Tier 1 System Resources. This augmentation amount will be determined by subtracting the forecast of annual firm energy loads to be sold under the Tier 1 Composite Customer Charge from the annual energy available from Tier 1 System Resources before augmentation is included. This amount will be subject to the augmentation limits established for augmentation for existing publics (section 3.2.3), DOE-Richland (section 3.2.4), new publics (sections 3.2.5), and DSIs (section 3.2.7).

If BPA has acquired specific resources for the purpose of augmentation, the costs of those resources will be included in the total costs of augmentation. BPA will forecast the costs of purchasing any remaining augmentation to provide the total augmentation needed to serve total annual energy loads to be sold under the Tier 1 Composite Customer Charge. The total costs of this augmentation will be allocated to the Tier 1 Composite Customer Charge cost pool.

3.2.2 Limits to Augmentation for Tier 1 System Resources

The Tier 1 System Resources may be augmented beyond the specific resources and contracts discussed above. This augmentation would be in addition to the output of Tier 1 System Resources and may increase each customer's CHWM (and thereafter, continue to be reflected in its RHWM.) Augmentation amounts are limited during the term of the TRM. Augmentation for existing publics is limited to a maximum amount determined necessary in setting the CHWMs, but will not exceed 300 aMW. As an additional limit, Augmentation for Existing Publics will also not cause the output of Tier 1 System Resources to exceed 7,400 aMW.

Specific augmentation exceptions are allowed for new publics, DSI sales, and certain U.S. Department of Energy (DOE–Richland) load; these exceptions are detailed below. Augmentation for these exceptions will not affect the CHWM of other customers. To the extent such exceptions occur, the costs for this augmentation will be shared by all Tier 1 rate purchasers. Slice percentages will be adjusted downward in order to maintain the same firm output from Tier 1 System Resources for each Slice customer. The circumstances where augmentation may be included in Tier 1 System Resources with an adjustment to Slice percentages are as described in section 3.3.

3.2.3 Augmentation of Tier 1 System Resources for Existing Publics

In the calculation of CHWM amounts, BPA will establish the amount of augmentation that is added to the Tier 1 System Resources for existing publics. This amount of augmentation will be between 0 and 300 aMW. To determine the specific augmentation, the output of Tier 1 System Resources for FY 2012, as forecast in FY 2011 and as specified in section 3.1, is subtracted from the adjusted Measured 2010 Load established in the CHWM determination process, as specified in section 2.1. The resulting amount of augmentation is subject to the following limitations:

1) If the result is zero or less, the augmentation amount will be zero.
2) If the result is greater than zero, then the augmentation amount is the lesser of the result or 300 aMW, subject to the limit in 3) below.
3) The total amount of CHWMs will not exceed 7,400 aMW in this calculation. This may reduce the result in limitation b).

3.2.4 Augmentation for Service to DOE-Richland

DOE-Richland has the right to increase its CHWM by up to 70 aMW in order to serve new on-site defense materials production and waste processing/disposal loads, if such loads occur. If such loads are added, BPA will augment Tier 1 resources up to 70 aMW, as necessary, to avoid reducing the CHWMs of other customers and will include these augmentation costs in Tier 1 rates.

3.2.5 Augmentation for New Publics

BPA may augment the Tier 1 resources up to 250 aMW for the CHWMs of New Publics during the term of the Regional Dialogue contracts. Specific amounts of this 250 aMW are also available for the load growth of tribal utilities formed since FY 2000. To the extent that requests for net requirement load service for New Publics exceed the 250 aMW CHWM limit, then the New Publics may purchase the remainder of their net requirements at Tier 2 rates.

3.2.6 Rate Case Limits for New Publics

Augmentation of Tier 1 System Resources for CHWM additions for New Publics is limited to 50 aMW for each Rate Period, except for amounts provided under the exceptions for small New Publics and tribal utilities discussed in section 2.1.8.

3.2.7 Augmentation for DSI Loads

BPA is still exploring alternatives for providing service benefits to DSIs. If BPA decides to sell power to the DSIs, BPA will augment the Tier 1 System Resources for this service. Augmentation for such sales will not decrease the publics' CHWMs. *See* section 10.3 for further discussion regarding DSI service.

3.2.8 Determining Augmentation Amounts Each Rate Period

The actual amount of augmentation of Tier 1 System Resources for each Rate Period will be determined in the RHWM Process. Augmentation amounts determined for each Rate Period will generally be equal to or lower than the allowable amounts because the RHWMs set a cap on Tier 1 rate power available for each utility's Tier 1 purchase from BPA in that Rate Period. A utility that loses load may not be able to purchase its full RHWM amount because its Tier 1 purchase is limited by its Net Requirement. Augmentation amounts will be determined in the RHWM Process when BPA forecasts the output of Tier 1 System Resources and the amount of load to be served at Tier 1 rates. During the RHWM Process, BPA will establish a forecast of the total amount of RHWM that customers are expected to not purchase during the upcoming Rate Period. The treatment for this unused RHWM is discussed in section 2.2. The augmentation amounts for sales to DSI customers will be established in the applicable rate case.

3.2.9 Rate Treatment for Excess Augmentation Purchases

BPA may acquire long-term resources during the term of the Regional Dialogue Contracts in anticipation of augmentation needs for future rate periods. If unused RHWM causes long-term augmentation resources to exceed the amount of augmentation established for a Rate Period, in the applicable rate case BPA will establish the cost or value of the excess augmentation for inclusion in the Composite Customer rate. The cost or value of the excess augmentation will be equal to the forecast market value of the power minus the cost of the excess augmentation.

3.2.10 Tier 1 System Resources Not Augmented for Loss of Resource

In the event that there is a loss of Tier 1 System Resources subsequent to August 15 of the Forecast Year, Tier 1 System Resources will not be augmented for the loss of the resource. However, that loss of resource may be recognized in the ensuing rate proposal in determining the Tier 1 costs of serving load. In this instance, any costs of necessary replacement resources will be included in Balancing Power Purchases for that Rate Period.

3.2.11 Rate Treatment When Augmentation Amounts Are Not Established Prior to the Initial Proposal

Augmentation amounts that are not secured by contract purchases prior to the final rate proposal will have the forecast costs established based on expected market prices during the Rate Period.

3.2.12 Source of Forecast Data and Customer Review Rights

The source of the data to establish the output of Tier 1 System Resources is the most recently published BPA White Book, or its successor, adjusted for known changes after publication. During the RHWM Process, customers will have the right to review the data and assumptions used to establish the forecast of the output of Tier 1 System Resources. Such review shall include the right to request the data from BPA and receive clarification of the data and the

forecast in general, and to offer modifications. However, the decisions and results of the RHWM Process will not be subject to alternative dispute resolution.

3.3 Balancing Power Purchases

BPA replaces the lost flexibility of the FCRPS of serving monthly, diurnal, and hourly variations in load through Balancing Power Purchases. Balancing Power Purchases can be market power purchases or resource acquisitions. The costs of resource acquisitions to serve capacity requirements of the FCRPS will be allocated to balancing power purchases. The forecast costs of Balancing Power Purchases are allocated to the Non-Slice Customer Charge cost pool. Customers purchasing the Slice product do not receive a share of Balancing Power Purchases and they do not pay the costs of Balancing Power Purchases. There is no true-up of forecast Balancing Power Purchase costs to actual costs.

3.4 Slice Amounts

The Slice percentage for each customer purchasing Slice will be determined by contract prior to FY 2012, and will not change during the Slice contract period, except in the two following situations.

3.4.1 Reduction in Slice Percentage Due to Load Loss

First, the Slice percentage will be reduced when a Slice customer's retail load loss reduces its Net Requirement to less then its Slice percentage of the forecast output of Tier 1 System Resources after the Slice customer has exhausted its ability to remove resource amounts consistent with BPA's 5(b)9(c) Policy. In this case, the Slice customer's block purchase will be zero and the total Net Requirement will be served by the Slice purchase. Any revenues

associated with BPA's resale of power due to reductions in the Slice percentage or Block purchase for this reason will be treated as specified in section 2.2.

3.4.2 Reduction in Slice Percentage Due to Specified Augmentation

Second, the Slice percentage will be recalculated when augmentation purchases are made for New Publics, for DSI power sales, and for DOE-Richland, as discussed in section 3.2. The calculation that was used to determine the original Slice percentage prior to these specified augmentation purchases will be reduced to include the amount of additional augmentation purchased for New Publics, for DSI power sales, and for DOE-Richland.

3.4.3 Effects of Reduction in Slice Percentage

When the Slice percentage is reduced as a result of either of the aforementioned situations, the Slice billing determinant for the Composite Customer rate will be reduced. The reduction of the Slice percentage also reduces the billing determinant for the Slice Customer rate.

3.5 Slice Resources Equal Tier 1 System Resources

The Slice resources will be comprised of the same resources, contract purchases and contract obligations used to determine Tier 1 System Resources, as described in section 3.1. Slice customers will share in any costs or revenues associated with the Tier 1 System Resources and will receive a commensurate amount of power and scheduling flexibility from the Tier 1 System Resources. Known costs and revenues associated with the Tier 1 System Resources will be included in the Composite Customer cost pool, which is charged to all Tier 1 customers, including Slice customers. These costs and revenues will be subject to the annual Slice True-Up process, as discussed in section 5.4, along with other costs and revenues in the Composite Customer and Slice Customer cost pools.

Slice customers will pay a percentage share (equal to the Slice percentage, also known as the Slice TOCA, *see* section 6.1.2) of the gross costs of augmentation of Tier 1 System Resources. Slice customers will receive a percentage share (equal to the Slice percentage) of these augmentation power purchase amounts as determined in the final rate proposal for the applicable Rate Period in the same amounts and shape for which all other Tier 1 customers are charged.

Slice customers will also pay a percentage share (equal to the Slice percentage) of all costs of augmentation for other purposes (sections 3.2.4, 3.2.5, and 3.2.7) established in this TRM. For these specific amounts, the Slice percentage will be recalculated as discussed in section 3.3. Slice customers will receive a percentage share (equal to the Slice percentage) of these augmentation power amounts as determined in the final rate proposal for the applicable rate period in the same amounts and shape for which all other Tier 1 customers are charged.

Slice customers will not pay for any of BPA's Balancing Power Purchases, nor will they receive any power from BPA's Balancing Power Purchases.

3.6 Federal System Resources Acquired for Tier 2 Service

BPA will acquire the resources necessary to serve loads that customers elect to place above-RHWM load on BPA, to be served at Tier 2 rates. These resources may consist of contracts for the output of specific resources, a system sale from another utility, or market purchases. BPA may use available energy from Tier 1 System Resources for service to Tier 2 customers to the extent any energy is available for the Rate Period. However, the use of such energy shall be charged to the Tier 2 cost pool at the full forecast market value for that energy and the resulting revenue will be credited to the appropriate Tier 1 cost pools. The appropriate Tier 1 cost pool for

firm energy is the Composite Customer cost pool. The appropriate Tier 1 cost pool for secondary energy is the Non-Slice Customer cost pool.

4 COST ALLOCATIONS

The cost allocation methods described in this section are designed to support a tiered rate design. Further, due to the differences in products offered to customers, the allocation of the revenue requirement also addresses the cost distinctions among the products.

4.1 Cost Allocation Principles

The following principles were applied in developing the cost allocation methods and form the basis to address circumstances that may arise during the term of the CHWM Contracts but are not specifically addressed here.

Principle #1: Tiering is a ratemaking construct implemented through an allocation of costs rather than an allocation of power.

Principle #2: Tier 1 costs will be kept separate and distinct from Tier 2 costs. Tier 2 costs will be recovered from Tier 2 customers. Tier 1 costs will be recovered from Tier 1 customers. However, Tier 2 costs may be recovered from Tier 1 customers only when it is necessary to timely ensure BPA's cost recovery or to conform to court order. Individual Tier 2 cost pools are to be kept separate from one another. Purchasers in one Tier 2 cost pool will not be responsible for costs incurred on behalf of another Tier 2 cost pool.

Principle #3: The separation of costs between the tiers and among the Tier 2 cost pools is achieved through the ratemaking process and will not affect the operation or dispatch of the FCRPS. BPA will use available resources to serve system load in

the most efficient and cost effective manner possible, without considering the ratemaking aspects of tiering.

Principle # 4 The ratemaking separation of costs between the tiers and among the Tier 2 cost pools will not be necessarily 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 section shall govern BPA's ratemaking.

4.2 Cost Allocation Method

In each applicable rate proposal, BPA will allocate costs into three cost pools for determining Tier 1 rates and one or more Tier 2 cost pools corresponding to costs for each Tier 2 rate alternative. The cost pools are: Tier 1 Composite Customer cost pool, Tier 1 Slice Customer cost pool, Tier 1 Non-Slice Customer cost pool, and Tier 2 cost pools. The Cost Allocation Table, Table 4.1, shows an example of the cost allocation based on the 2007 power rate case costs and is intended as a determinative guide in allocating costs in future Rate Periods. Although Table 4.1 contains one Tier 2 cost category, additional Tier 2 categories will be added as additional Tier 2 rate alternatives are developed and the associated cost pools are established.

The allocation of costs into cost pools is a ratemaking exercise that falls within the province of section 7 of the Northwest Power Act. The establishment and modification of any allocation will be conducted consistent with the provisions of section 7(i). The Cost Allocation Table will be modified through the provisions determined in a section 7(i) rate proceeding.

4.3 Cost Categories and Cost Allocation Table

The Cost Allocation Table is the means of implementing the allocation of costs among the cost pools. The Cost Allocation Table will conform to BPA's cost accounting reporting of expenses and may be modified from time to time to incorporate changes of such reporting. Such modifications will not change the allocation of costs to the respective cost pools. The allocation of costs among the cost pools will form the basis for setting Tier 1 and Tier 2 rates for customers electing tiered service at tiered rates.

4.3.1 The Composite Customer Cost Pool

The Composite Customer cost pool is comprised of all Tier 1 costs or credits functionalized to the Power function unless specifically meeting the criteria for either the Slice Customer cost pool or the Non-Slice Customer cost pool.

4.3.2 The Slice Customer Cost Pool

The Slice Customer cost pool is comprised of all Tier 1 costs or credits that are specifically tied to the operation or administration of the Slice product, the Slice rate, and/or the Slice contract.

4.3.3 The Non-Slice Customer Cost Pool

The Non-Slice Customer cost pool is comprised of all Tier 1 costs or credits that are specifically tied to the operation or administration of the Load Following or Block product, including the Block portion of the Slice/Block product, and/or the associated CHWM Contract. It is also comprised of: any costs or credits specifically and solely tied to BPA's marketing and administration of secondary power, including the wheeling of such power; the costs or credits of Balancing Power Purchases; the costs or credits arising from risk mitigation (*e.g.*, Planned Net Revenues for Risk); and the costs or credits arising from capacity resource purchases that are not included in the Slice product.

4.3.4 Tier 2 Cost Pools

The Tier 2 cost pools are comprised of all Tier 2 costs or credits that are specifically tied to the operation or administration of Tier 2 products. The costs of all power purchases and resource acquisitions including any applicable RSS charges, on a forecast basis, used to serve the loads of Tier 2 purchasers, will be included in a Tier 2 cost pool. A uniform adder will be included in the Tier 2 cost pools to account for the costs of operating and administering the Tier 2 products, otherwise known as the Overhead Cost Adder. The forecast revenue from the Overhead Cost Adder will be credited to the Composite Customer Charge cost pool. *See* section 7.3 for a fuller discussion of costs allocated to Tier 2 rate pools.

4.4 Inclusion of New Costs or Credits

All BPA costs functionalized to the Power function will be included in the Cost Allocation Table, Table 4.1. New costs not previously included in the Cost Allocation Table will be allocated to the cost pools based on the cost allocation principles in section 4.1 when they arise. BPA will propose an allocation of the new costs and credits to the appropriate cost pools in a section 7(i) rate proceeding. *See* Slice True-Up in section 5.4 for related issues. Rate case parties will be afforded the opportunity to clarify and challenge the proposed allocation in the rate proceeding. The Administrator will determine the proper allocation of the new costs or credits in the final record of decision.

4.5 Interest Earned on the Bonneville Fund

On the first day of the Slice contract, October 1, 2001, BPA had financial reserves attributed to the Power function of $495.6 million. All preference customers contributed to the accretion of these reserves. At that time, BPA had some uncertain liabilities and assets arising from disputes

over transactions during the California energy crisis which have not yet been resolved on a final basis. However, beginning in FY 2002, Slice customers have not further contributed to the accretion of reserves.

BPA will allocate an interest credit based on that pre-FY 2002 level of reserves, $495.6 million, as adjusted for any eventual resolution of the uncertain assets and liabilities, to the Composite Customer cost pool. The Non-Slice Customer cost pool will be allocated a credit equal to the total anticipated credit earned on Bonneville Fund balances attributed to the Power function less the amount of interest credit included in the Composite Customer cost pool. The credit to the Non-Slice Customer cost pool will be negative if the interest credit allocated to the Composite Customer cost pool is greater than the total interest credit for a year.

If BPA recovers any receivables that are outstanding from the pre-FY 2002 period, and if Slice customers do not otherwise benefit from this receipt (*e.g.*, through the Slice True-Up), then the amount of that receipt will be added to the $495.6 million used for calculating the interest credit included in the Composite Customer cost pool. If it is determined that BPA is liable for settlements and judgments applicable to transactions in the pre-FY 2002 period and if Slice customers do not otherwise contribute to paying for these settlements and judgments (*e.g.*, through the Slice True-Up), then the amount of those settlements and judgments will be subtracted from the $495.6 million used for calculating the interest credit included in the Composite Customer cost pool.

5 RISK MITIGATION

5.1 Overview of risk in the TRM

In each rate case, BPA will define risk mitigation mechanisms and set rates to support BPA's then-current Agency financial risk standard(s). The Agency financial risk standard(s) is (are) set in BPA's 10-Year Financial Plan, or its successor, subject to any required review in a 7(i) rate proceeding.

[this italicized paragraph is for context and will not appear in the Methodology]*As of November 2007, the Agency financial risk standard is the TPP standard of 95 percent for two-year rate periods. As circumstances change, BPA may modify that standard, e.g., by changing the percentage, by adding a Vendor Payment Probability standard, or in other ways. As of November 2007, BPA's practice for implementing the Agency financial risk standard is to apply the same standard independently to its Power function and its Transmission function. In the future, BPA may be able to create an implementation practice that incorporates: 1) simultaneous assessment of power and transmission risks and direct measurement of the then-current metric (e.g. TPP) for Agency financial risk; and 2) apportioning of any responsibility between power rates and transmission rates for increasing the strength of risk mitigation.*

5.2 Risk in Tier 2

Tier 2 risk mitigation will include contract terms and conditions, such as the requirement that Tier 2 service be take-or-pay, to reduce the risk that BPA acquires power for forecast Tier 2 load that does not materialize. Risks in Tier 2 will be assessed both for each Tier 2 rate alternative and collectively for all rate alternatives in each rate case to determine if the terms and conditions have adequately mitigated risks to BPA's risk standards. BPA will include any supplementary risk mitigation necessary to meet BPA's risk standards into Tier 2 rates. Total Tier 2 risk

mitigation will be structured so that the risk in Tier 2 does not increase the costs allocated to Tier 1 cost pools, nor does it require any enhancement of other Tier 1 risk protection mechanisms, such as PNRR or CRACs, beyond what would have been required absent sales at the Tier 2 rate. The determination of the costs of risk included in the Tier 2 cost pool, or the mitigation of such risk, is decided in rate cases and is not subject to alternative dispute resolution.

5.3 Risk in Tier 1

BPA will assess the risks related to the costs and revenues allocated to the Tier 1 costs pools and design risk mitigation measures and set rates for Tier 1 so that the Tier 1 rates meet the BPA's risk standard(s). BPA will continue the current approach of using true-ups for Slice risk mitigation. If this method is demonstrated to cause cost shifts between Slice and non-Slice customers, BPA will address this issue in the appropriate rate case. Risk mitigation for non-Slice products will be determined in each rate case.

[this italicized paragraph is for context and will not appear in the Methodology]*The following paragraph is included because there may be situations, expectedly rare, where the sum of the risk mitigation measures included in Tier 1 and in Tier 2 does not cover the whole risk. Normally, an assessment of risks of two pieces that encompass the whole will produce an answer greater than if the risks were assessed as the whole. Therefore, BPA believes that the structure outlined above will produce more risk protection than if risks were assessed together. However, this may not always be the case. Therefore, the following paragraph:*

Notwithstanding the efficacy of risk mitigation measures individually included in Tier 1 and Tier 2 rates, it may be possible that the risk to the Power function is not fully mitigated to BPA's

risk standards. BPA will include in its risk assessment an examination of the aggregate Power function. Should Power function risks not be fully mitigated to meet BPA's risk standards, BPA will propose an allocation of the remaining risk mitigation between the tiers in the applicable rate case and decide the issue in that proceeding.

5.4 Slice True-Up

Slice customers will have an annual True-Up for expenses and credits in the Composite Customer cost pool (*see* Table 4.1, Composite lines) that is the basis for the Composite Customer rate. The expenses and credits in the Slice Customer cost pool (*see* Table 4.1, Slice lines) will also be subject to an annual True-Up process. The Slice Customer cost pool is the basis for the Slice Customer rate (*see* section 6.1.5). The annual Slice True-Up Adjustment will be calculated for each fiscal year as soon as BPA's audited financial data are available (usually in November of each Slice contract year).

The annual Slice True-Up Adjustment for the expenses and credits in the Composite Customer cost pool will be calculated by subtracting the average Composite Customer cost pool costs for the applicable Rate Period, upon which the Composite Customer rate is based, from the actual Composite Customer cost pool costs for the applicable fiscal year and multiplying the difference by the customer's Slice percentage. The annual Slice True-Up Adjustment for the expenses and credits in the Slice Customer cost pool will be calculated by subtracting the average Slice Customer cost pool costs for the applicable Rate Period upon which the Slice Customer rate is based, from the actual Slice Customer cost pool costs for the applicable fiscal year. This amount is then allocated to each Slice customer, as appropriate, based on the applicable Slice percentages.

Background/Context for Slice True-Up Audit Issue

[these italicized paragraphs are for context and will not appear in the Methodology]*The primary impetus for the current Slice True-Up audit provisions was to give Slice customers an ability to verify that BPA had properly allocated costs or revenue credits in accordance with the Slice Rate Methodology and new costs that appeared after rates were set. The associated dispute resolution provisions were likewise aimed mainly at resolving disputes over the proper allocation of such costs and revenue credits. A secondary purpose was to give customers a means of verifying that costs recovered through the True-Up were correctly accrued. Both these purposes represent very legitimate customer interests.*

After 2011, two fundamental differences in conditions call for a different approach to addressing these legitimate customers' interests. First, the new rates and contracts increase the likelihood that all customers, not just Slice customers, will have a keen interest in ensuring that such post-rate case allocations are done properly. Currently, all customers are interested in the allocation between Slice and non-Slice rates. Under the proposed Regional Dialogue Tiered Rates Methodology, all customers will want to be sure that new costs are correctly allocated between Tier 1 and Tier 2 rates. Many customers will also have an interest in proper allocation of costs among different Tier 2 rates. Second, the days of 5-year rate periods are very likely gone, and with that change, the frequency of significant new costs appearing in True Up will decline because the time between rate cases will be shorter.

Given these fundamental changes, BPA believes it will serve all parties best to have a single forum for verification that BPA has properly allocated costs and credits between Slice and non-Slice rates, and between Tier 1 and Tier 2 rates. BPA believes that forum is more efficiently and logically the rate cases. Rate cases have not historically "looked backwards" at cost allocations

in the prior rate period, but BPA now proposes that this ex post review be added to future cases. For Slice, a verification process focused narrowly on the second interest would be appropriate. The approach would be specifically as follows.

5.4.1 New Costs or Credits in the Slice True-Up

In the annual Slice True-Up, BPA will allocate new costs or revenue credits that arise or become known after the rates are developed (during a Rate Period) to Slice customers based on the TRM cost allocation principles and methodology (*see* section 4.1). Slice customer challenges to BPA allocation decisions on new cost or revenue credits during the rate period will be addressed in the next scheduled rate case. If a different cost allocation than what was implemented through the True-Up is adopted, the Slice customers will be compensated or charged based on their over- or under-payment, respectively.

5.4.2 Verification of Slice True-Up

Slice customers will be charged all actual costs and credits assigned to the Power function by BPA, except for specific excluded costs (see section 4.3.3). All customers will have the right to verify, through a verification process, that BPA has correctly calculated the amount of each cost that the True-Up calculation is based on. The verification process will focus strictly on calculation errors, and will not enable customers to question or dispute accounting, policy, management and other similar issues. The verification process will be facilitated by BPA and will begin in January of each fiscal year, following the True-Up Adjustment calculation for the previous fiscal year. BPA will work with customers to develop the verification process.

In the event BPA incurs a new cost that is assigned to the Power function and is not one of the specifically excluded costs, Slice customers will pay their allocated share of the cost but, along

with other customers, will have the right to contest allocation of that cost to the Power function and in turn to a Tier 1 cost pool in the next rate case. All customers also can review a limited set of existing cost accounts to ensure that the contents of those accounts comport with the specifically excluded costs.

5.4.3 Formula for True-Up calculation

Actual Composite Customer cost costs pool minus the average Composite Customer cost pool costs (for applicable Rate Period upon which the Composite Customer rate is based) will result in the Slice True-Up Adjustment Charge.

If the Slice True-Up Adjustment Charge is positive, then this results in a charge that is applied to the Slice customer's bill. If the Slice True-Up Adjustment Charge is negative, then this results in a credit that is applied to the Slice customer's bill. The Slice True-Up Adjustment Charge will be multiplied by the customer's Slice percentage to determine the amount that is owed by or credited to that customer.

The Actual Composite Customer Charge cost pool will include expenses and revenues accounted for by BPA in the applicable fiscal year, in accordance with Generally Accepted Accounting Principles (GAAP) and such expenses and revenues are used in the calculation of Accumulated Annual Net Revenues (AANR).

The Actual Composite Customer Charge cost pool will include a component (Minimum Required Net Revenue) for the amount in a fiscal year by which BPA's actual cash requirements (generally generation amortization and irrigation assistance payments) to the U.S. Treasury exceed the total actual non-cash expenses in the Composite Customer cost pool.

The final Slice True-Up Adjustment Charge for each customer shall be applied either as a one-month credit (if the adjustment is negative) or as a three-month charge (if the adjustment is positive, and spread equally across the three months) following the month the Slice True-Up Adjustment Charge is calculated. Slice customers may have an option of paying the entire charge in one month.

BPA will provide a preliminary estimate of the Slice True-Up Adjustment Charge prior to providing the Slice True-Up Adjustment Charge that is based on audited financial data.

Interest shall be computed and added to the Slice True-Up Adjustment Charge. The end of the interest period is defined as follows:

- If the Slice True-Up Adjustment Charge is a credit to the Slice customer, the period for interest computation shall end at the due date of the bill that contains such credit.
- If the Slice True-Up Adjustment Charge is a charge payable to BPA, the period for interest computation shall end at the due date for each of three bills. For Slice customers who opt to pay the charge in one month, the period for interest computation shall end at the due date for one bill.

6 TIER 1 RATE DESIGN

The PF Tier 1 rate design described in this section is applicable to customers who receive a CHWM Contract. If a customer chooses a Regional Dialogue Contract without a CHWM, the design of PF rates applying to such customers will be determined in the general rate cases that occur during the term of those contracts.

The Tier 1 rate structure consists of three elements: Customer Charges; a Demand Charge; and a Load Shaping Charge. Each of these is described below. In addition, BPA may propose a rate for load following or ramping in general rate cases during the term of the CHWM Contract. *See* section 6.4. For a customer that applies non-Federal resources to serve its above-RHWM load, a Resource Shaping Charge will apply, as described in section 9.

BPA will consider customer requests to shape Customer Charges within the Fiscal Year to mitigate adverse cash flow effects on a customer resulting from this rate design. Such reshaping will recover the same amount of dollars within the Fiscal Year. The reshaping will be accomplished prior to the Fiscal Year as agreed between BPA and the customer. The reshaping of the Customer Charges will take into account the Customer Charges, a forecast of Load Shaping Charges, and a forecast of Demand Charges. The reshaping will be accomplished by specifying 12 Composite Customer rates for the individual customer that recover, in total, the same amount of dollars as the constant Composite Customer rates applicable to that Fiscal Year. The reshaped charges will conform to the cash flow to the shape of the customer's Total Retail Load. Such reshaping requests will be considered to the extent that the aggregate reshaping for all customers so requesting does not create problems for BPA's cash flow, as determined solely by BPA.

6.1 Customer Charges

The Customer Charges are defined as the product of a billing determinant multiplied by a rate and will collect the majority of Tier 1 costs. There will be three Customer Charges calculated for each Rate Period: 1) a Composite Customer Charge that recovers the Composite Customer costs and applies to all customers with a CHWM regardless of the product choice among Load Following, Slice or Block; 2) a Non-Slice Customer Charge that recovers the Non-Slice Customer costs and applies to customers purchasing either the Load Following or Block products (including the Block portion of the Slice/Block product); and 3) a Slice Customer Charge that recovers the Slice Customer costs and applies to customers purchasing the Slice product. Each customer will pay for its prorated share of each cost pool (Composite, Non-Slice and Slice).

6.1.1 Tier 1 Cost Allocation (TOCA) Billing Determinants

A Tier 1 Cost Allocation (TOCA) will be calculated for each customer for each Rate Period. A customer's TOCA is its billing determinant and represents its percentage share of the Tier 1 applicable cost pools. Each customer's TOCA will be based on the lesser of the customer's RHWM or the customer's forecast Net Requirement, and is calculated as a percentage of the total of RHWMs for all customers (whether or not they have CHWM Contracts). A customer's TOCA may change during the rate period if that customer's Net Requirement (as calculated for planned Net Requirements customers or as forecast for actual Net Requirements customers) results in a change in eligibility to purchase power at Tier 1 rates. Expressed as a formula, the TOCA is calculated as follows:

$$TOCA = \frac{\min(RHWM, Netreq)}{\sum RHWM} \times 100$$

where:

TOCA = customer's Tier 1 Cost Allocation.

RHWM = customer's Rate Period High Water Mark

Netreq = forecast of the customer's Net Requirement from the RHWM Process

$\sum RHWM$ = sum of RHWM for all customers (expected to be 100 percent of the output of Tier 1 System Resources)

6.1.2 Slice Customer Non-Slice TOCA Billing Determinants

A customer purchasing the Slice/Block product will have two TOCAs, one for its Slice product purchase and a separate TOCA for its Block product purchase. The TOCA associated with its Block product purchase is referred to as its Non-Slice TOCA and will be defined as its the TOCA (as defined in section 6.1.1) minus its Slice percentage (as defined in section 3.4). Expressed as a formula, the Non-Slice TOCA for Slice product purchasers is calculated as follows:

$$NonSliceTOCA = TOCA - Slice\%$$

where:

Slice% = a customer's Slice percentage, also equal to its Slice TOCA.

6.1.3 Composite Customer Rate

The Composite Customer Rate will apply to all customers with a CHWM Contract. As stated earlier, the Composite Customer Rate will recover all costs allocated to the Tier 1 Composite Customer cost pool and will be a dollar-per-one percent of the output of Tier 1 System Resources (*see* Table 4.1 for listing of specific cost items in the Composite Customer Rate).

$$CompositeRate = \frac{CompositeCost}{\sum TOCA}$$

where:

CompositeCost = Tier 1 costs allocated to the Composite Customer cost pool

$\sum TOCA$= the sum of TOCAs for all Tier 1 purchasers

6.1.4 Non-Slice Customer Rate

The Non-Slice Customer Rate will apply to customers purchasing the Load Following or Block products, including the Block portion of the Slice/Block product. Generally, the Non-Slice Customer Rate will collect those costs that the Slice product specifically excludes and will credit forecast net secondary revenues against those costs (*see* Table 4.1 for listing of specific items in the Non-Slice Customer Rate). The Non-Slice Customer Rate will recover the costs allocated to the Non-Slice Customer cost pool and will be a dollar-per-one percent of the output of Tier 1 System Resources.

$$NonSliceRate = \frac{NonSliceCost}{\sum NSCTOCA}$$

where:

NonSliceCost = BPA's Tier 1 Non-Slice Costs

$\sum NSCTOCA$= the sum of TOCAs for Load Following and Block purchasers plus NonSliceTOCA for Slice purchasers

6.1.5 Slice Customer Rate

The Slice Customer Rate will apply to customers purchasing the Slice portion of the Slice/Block product. Generally, the Slice Customer Rate will collect those costs that the Slice product specifically includes (*see* Table 4.1 for listing of specific items in the Slice Customer rate). The

billing determinant will be the customer's contractually specified Slice percentage. The Slice Rate will consist of the costs allocated to the Slice cost pool and will be a dollar-per-one percent of the output of Tier 1 System Resources.

$$SliceRate = \frac{SliceCost}{\sum SCTOCA}$$

where:

SliceCost = BPA's Tier 1 Slice Costs

$\sum SCTOCA$= the sum of TOCAs for Slice purchasers

6.2 Load Shaping Charge

Customers will be charged or credited at Load Shaping rates based on the need to shape the firm output of Tier 1 System Resources to the diurnal/monthly shape of a customer's Tier 1 load. This charge is applicable only to customers purchasing Block (including the Block portion of the Slice/Block product) or Load Following products. Customers purchasing the Slice product do not receive this load shaping service.

6.2.1 Load Shaping Charge Billing Determinants

As part of establishing a Load Shaping Charge, BPA will develop a System Shaped Load for each customer. BPA will then compare a customer's System Shaped Load to its actual Tier 1 load to establish a load shaping billing determinant. During billing periods when its System Shaped Load exceeds its actual load, the customer will receive a credit. During periods when the System Shaped Load is less than the actual load, the customer will receive a charge.

The first step in calculating the Load Shaping Charge billing determinants will be to identify the firm output of the Tier 1 System Resources. For each Rate Period, BPA will begin with the

forecast of the firm energy output (*i.e.*, critical energy) for Tier 1 System Resources for each diurnal (Heavy Load Hour (HLH) and Light Load Hour (LLH)) period in each month of the Rate Period (24 monthly/diurnal values). Once established in the rate case, these 24 monthly/diurnal values will not be modified for the duration of the Rate Period.

The second step in calculating the Load Shaping Charge billing determinants will be to identify the System Shaped Load for each customer. To calculate the System Shaped Load for each customer, BPA will multiply the customer's TOCA by the monthly/diurnal values from the first step. The customer's System Shaped Load represents the amount of energy the customer would receive in each monthly/diurnal period if its forecast Tier 1 load was in the shape of the output of Tier 1 System Resources.

$$SystemShapedLoad = T1SRoutput \times TOCA$$

where:

SystemShapedLoad = the customer's System Shaped Load for each monthly/diurnal period;

T1SRoutput = the output of the Tier 1 System Resources for each monthly/diurnal period, expressed in kilowatthours;

TOCA = the customer's TOCA for that year.

The third step in calculating the Load Shaping Charge billing determinants factors in the actual monthly/diurnal load for each customer. The monthly/diurnal Load Shaping Charge billing determinants are calculated by subtracting a customer's System Shaped Load from its actual Tier 1 load in each monthly/diurnal period. The actual Tier 1 load for each Block customer will

be its billed contract power purchase. The actual Tier 1 load for each Load Following customer will be its actual billed energy.

6.2.2 Load Shaping Rate

In each rate case, the Load Shaping Rate for each monthly/diurnal period during the Rate Period (24 monthly/diurnal values) will be the forecast market prices for each monthly/diurnal period.

6.2.3 Calculating the Load Shaping Charges

The Load Shaping Charges will be the Load Shaping Charge billing determinants multiplied by the Load Shaping rates. If a specific Load Shaping Charge billing determinant is positive, the result will be a charge on the customer's bill. If a specific Load Shaping Charge billing determinant is negative, the result will be a credit on the customer's bill.

6.2.4 True-up of Load Shaping Charge for Load Following Customers

Load Following customers will be subject to an annual true-up of its total annual Load Shaping Charges after the conclusion of each Fiscal Year. This true-up will compare the forecast of annual Tier 1 load for each customer with its actual annual Tier 1 load. There are two situations where a calculation will be required to determine whether there will be a true-up. The first situation occurs when actual annual Tier 1 load is less than the customer's RHWM. In this case, BPA will true-up the Load Shaping Charge to reflect that the customer was charged or credited at the Load Shaping Rate for loads less than its RHWM. To the extent actual annual Tier 1 load is lower because forecast above-RHWM load did not occur, there will be no true-up for the forecast above-RHWM load. The second situation occurs when the forecast Net Requirement used to determine the customer's TOCA was less than its RHWM, but its actual Tier 1 load was greater than its RHWM. In this case, BPA will true-up the Load Shaping Charge to reflect that a

portion of the Tier 1 load should have been charged a rate less than the Load Shaping Rate. BPA will adjust the customer's Load Shaping Charge payments to reflect the difference between the annual average of the Load Shaping Rates and BPA's Tier 1 Composite Customer Rate plus Non-Slice Customer Rate, expressed in $/MWh, called the Load Shaping Charge True-up rate (*see* section 6.2.4.3). The Load Shaping Charge true-up is designed to avoid crediting or charging a customer at a market-based rate for energy that was or should have been purchased from BPA at its cost-based Tier 1 rates.

6.2.4.1 Identifying the Need for a Load Shaping Charge True-up

The actual annual Tier 1 energy load for a Load Following customer will be based on billing data. A customer's actual annual Tier 1 energy load will be compared to its RHWM, as well as its forecast Net Requirement used to determine its TOCA. If its actual annual Tier 1 load exceeds its RHWM and its forecast Net Requirement is not less than its RHWM, no true-up is needed. Under this circumstance, the customer was not over- or under-charged by use of the Load Shaping Rates.

If the customer's actual annual Tier 1 energy load is less than its RHWM, then BPA will true-up the Load Shaping Charge payments. Under this circumstance, the customer was either over- or under-charged by use of the Load Shaping Rates for the portion of actual annual Tier 1 load that was less than its RHWM. In this case, BPA will adjust the customer's Load Shaping Charge payments using the Load Shaping Charge True-up rate.

If the customer's forecast Net Requirement is less than its RHWM, but its actual annual Tier 1 load is greater than its RHWM, then BPA will true-up a portion of the Load Shaping Charge payments. Under this circumstance, the customer was over-charged by use of the Load Shaping

Rates for the portion of actual annual Tier 1 load that was less than its RHWM. In this case, BPA will adjust the Load Shaping Charge payments using the Load Shaping Charge True-up rate.

6.2.4.2 Load Shaping Charge True-up Billing Determinant

There are three equations used to determine the Load Shaping Charge True-Up billing determinant.

The first equation calculates a value *AnnualDeviation*, which is the amount of billed energy greater than or less than the amount of energy that was used to develop customer's the TOCA. This equation determines whether to use the *AboveForecast* or *AboveRHWM* equation.

The second equation applies only when *AnnualDeviation* is positive and calculates a value *AboveForecast*, which is the amount of RHWM energy that is greater than the amount of energy that was used to determine the customer's TOCA.

The third equation applies only when *AnnualDeviation* is negative and calculates a value *AboveRHWM*, which is the amount of above-RHWM energy for a customer.

BPA will calculate the difference between the energy used to determine the customer's TOCA and the actual Tier 1 billed energy during the year:

$$AnnualDeviation = ActualLoad - [TOCA \times T1SR]$$

where:

T1SR = annual Tier 1 System Resources used in calculation of the customer's RHWM, expressed in kWh

ActualLoad = actual annual Tier 1 load, expressed in kWh

If *AnnualDeviation* is positive, then the customer was charged for this energy at the Load Shaping Rates. BPA will then determine if the customer should have been charged at the Load Shaping Charge True-up rate or was appropriately charged the Load Shaping Rates. If the customer's RHWM is larger than the amount of energy used to develop its TOCA, then a portion of the energy should have been charged the Load Shaping Charge True-up rate. The following formula will be used to determine the amount of energy that is subject to the Load Shaping Charge True-up rate:

$$AboveForecast = [RHWM \times 1{,}000 \times hours] - [TOCA \times T1SR]$$

where:

hours= the total hours in the Fiscal Year (8,760 hours in a non-leap year and 8,784 hours in a leap year)

If *AboveForecast* equals zero, then no true-up is needed since all Load Shaping energy should be charged at the Load Shaping Rates. If *AboveForecast* is positive, then the customer will be refunded the lesser of *AnnualDeviation* or *AboveForecast* multiplied by the Load Shaping Charge True-up rate. *AboveForecast* cannot, by definition, be negative.

If *AnnualDeviation* is negative, then the customer was credited for this energy at the Load Shaping Rates. BPA will then determine if the customer should have been credited at the Load Shaping Charge True-up rate. The following formula will be used to determine the amount of energy to be credited at the Load Shaping Charge True-up rate:

$$AboveRHWM = [TRL - ExistingResources] - [RHWM \times 1{,}000 \times yhours]$$

where:

TRL= Total Retail Load in kWh

ExistingResources = Existing Resources

If *AboveRHWM* is equal to or larger than the absolute value of *AnnualDeviation*, then no true-up is needed. If *AboveRHWM* is positive but less than the absolute value of *AnnualDeviation*, then the customer will be charged the absolute value of *AnnualDeviation* minus *AboveRHWM* multiplied by the Load Shaping True-up rate. If *AboveRHWM* is negative, then the customer will be charged the absolute value of *AnnualDeviation* multiplied by the Load Shaping True-up rate.

6.2.4.3 Load Shaping Charge True-up Rate

The Load Shaping Charge True-up rate will be determined in each rate case as the difference between the Load Shaping Rate and the Tier 1 unit cost, expressed in $/MWh.

In each rate case, BPA will forecast the total Tier 1 energy billing determinants (monthly HLH and LLH differentiated) for all Block (including the Block portion of the Slice/Block product) and Load Following customers for the Rate Period. BPA will then multiply the total Tier 1 energy billing determinants by the Load Shaping Rates.

$$MktR = \left(LoadShapingRate \times FT1EBD\right)$$

where:

MktR= Total Block and Load Following energy revenue that would be collected if BPA applied the Load Shaping Rae to its Tier 1 energy forecast.

LoadShapingRate = Load Shaping Rate as described in section 6.2.2 in $/MWh

FT1EBD= Forecast of Tier 1 energy billing determinants for the Rate Period in monthly HLH and LLH MWh amounts.

The rate period net allocated costs (total allocated costs reduced by revenues from net secondary sales, Demand Charges and Load Shaping Charges) for Block and Load Following customers will also be calculated. This is the forecast Tier 1 revenue received from Block and Load Following customers through their Composite and Non-Slice Customer charges.

$$BLFRnDLS = NonSliceCost + \left[CompositeRate \times \sum NonSliceTOCA\right]$$

where:

BLFRnDLS = Tier 1 net allocated costs for Load Following and Block purchasers (including the Block purchased by customers purchasing the Slice product) net of revenues from net secondary sales, Demand Charges and Load Shaping Charges

NonSliceCost = BPA's Tier 1 Non-Slice Costs

CompositeRate = The Composite Customer Charge rate as described in section 6.1.3

$\sum$*NonSliceTOCA* = the sum of TOCAs for Load Following and Block customers plus NonSliceTOCA for Slice customers

The forecast Load Shaping Charge revenue will be added to the *BLFRnDLS* to create net allocated costs for Load Following and Block purchases that are net of net secondary sales and Demand revenue. This is the portion of the total net allocated costs that would be collected through an energy charge.

$$BLFRnD = BLFRnDLS + LoadShaping$$

where:

BLFRnD = Tier 1 net allocated costs for Load Following and Block purchasers (including the Block purchased by customers purchasing the Slice product) net of revenues from net secondary sales and Demand Charges

LoadShaping = Forecast Load Shaping revenue

The amount of revenue calculated for the *BLFRnD* will be subtracted from the amount of revenue calculated for the *MktR*. This difference will be divided by the sum of the *FT1EBD*. The quotient will equal the Load Shaping True-up rate used for the entire rate period.

$$LSTU = \frac{[MktR - BLFRnD]}{\sum FT1EBD}$$

where:

LSTU = Load Shaping True-up rate in $/MWh

6.3 Demand Charge

The Demand Charge is designed to send a marginal price signal to a limited portion of a customer's overall demand on BPA. The Demand Charge is applicable to customers purchasing Load Following and Block with Shaping Capacity products. The billing determinant will be

based on each utility's Customer System Peak (CSP) which is defined as the customer's single highest HLH Tier 1 hourly energy purchase from BPA during each month. After the customer's CSP is identified for each month, BPA will make the adjustments identified below to the CSP to calculate the Demand Charge billing determinant. The adjustments include a reduction to the CSP for average HLH energy use for the month and a reduction based on historical peak use (referred to as Contract Demand Quantity or CDQ, *see* section 6.3.1.2).

A third reduction will be made to the CSP if a customer makes a firm resource commitment for the rate period that is shaped into the Super Peak period as defined by BPA. The Super Peak period will be either two three-hour periods each day or a single six-hour period, all as determined in each rate case. The reduction to the CSP for a Super Peak resource is equal to the amount of additional capacity the customer commits to provide during Super Peak hours compared to the amount of capacity that would be provided if the same amount of energy was provided flat within the monthly HLH period. This reduction will be applied regardless of when the customer's actual CSP occurs. The total demand billing determinant cannot be reduced below zero.

Four quantities will be used in calculating a customer's Demand Charge billing determinant (or billing demand). These quantities are the Customer's System Peak on BPA (CSP), the average HLH energy use each month (aHLH), the customer-specific Contract Demand Quantity (CDQ) (*see* section 6.3.1), and the amount of Super Peak capacity provided above the amount of capacity included in the same amount of energy provided flat across the monthly/diurnal HLH period. The following formula will be used to calculate a customer's monthly Demand Charge billing determinant:

$$BillingDemand = \max(0, CSP - aHLH - CDQ - SuperPeak)$$

where:

BillingDemand = Demand Charge billing determinant

CSP = Customer System Peak, which is the customer's maximum hourly Tier 1 load placed on BPA during the heavy load hours of each month

aHLH = actual average Tier 1 energy purchased during the heavy load hours of each month

CDQ = Contract Demand Quantity

Superpeak = amount of additional capacity provided by a non-Federal resource over the amount of capacity provided by an equivalent amount of energy delivered flat across the monthly HLH period.

6.3.1 Contract Demand Quantity

The Contract Demand Quantity (CDQ) is a grandfathered quantity of demand that is subtracted from a customer's CSP as part of the process of determining the Demand Charge billing determinant. BPA will calculate 12 CDQs (one for each month) and identify those quantities in a customer's CHWM contract. The calculation for determining the customer-specific CDQs will be based on each customer's historical FY 2005-2007 monthly load factors applied to the customer's monthly FY 2010 TRL less monthly Existing Resources during heavy load hours. *The method for calculating the CDQ for current Slice and Block customers and new customers has yet to be developed.* Because CDQs cannot be determined until late in FY 2011, BPA will use a forecast of CDQ for each customer for setting rates in the WP-12 rate case. The actual CDQ will be used for customer bills during FY 2012-2013.

6.3.1.1 Calculation of the Historical (FY 2005-2007) Load Factor

A HLH load factor will be calculated for each customer for each month of the year. The load factor will be based on the average monthly CSP (Contract CSP) and the average monthly HLH energy (Contract aHLH) using FY 2005, 2006, and 2007 billing data. To calculate the load factor BPA will divide the Contract aHLH by the Contract CSP.

BPA will adjust the HLH load factor to assure that some portion of each customer's demand is on the margin. The adjustment will be accomplished by dividing the HLH load factor by 91 percent to produce an Adjusted HLH load factor.

6.3.1.2 Calculating CDQ

The Adjusted HLH load factors will be applied to the customer's Measured 2010 Load (*see* section 2.1.3 for description of Measured 2010 Load) to calculate the customer's CDQ. Once calculated, the CDQ will be included in the CHWM Contract for use during the contract term. The following formula will be used for each month of the Fiscal Year.

$$CDQ = \max(0, \frac{aHLH_{2010}}{adjLoadFac} - aHLH_{2010})$$

where:

$aHLH_{2010}$ = Average HLH energy purchase from BPA used in calculating CHWM for each month

$adjLoadFac$ = Adjusted HLH Load Factor for each month

6.3.2 Demand Rate

The Demand Rate will be based on the annual fixed cost (capital and O&M) of the marginal capacity machine as determined in each rate case. BPA will identify the marginal capacity

machine and the fixed costs associated with that machine for each rate period based on BPA's Resource Program and/or costs of BPA's recent capacity additions. If there are no recent capacity additions or Resource Program-identified capacity resources and costs, BPA will use a collection of third party sources to inform its decision. These third party sources include the Energy Information Administration, EPRI Technical Assessment Guide, the Northwest Power and Conservation Council, and Integrated Resource Plans of Pacific Northwest electric utilities. Identification of the marginal capacity machine and the fixed costs associated with that machine will be proposed in each rate case. The Demand Rate will be proportionally shaped to the HLH energy prices set for the Load Shaping Rates. The shape of the Demand Rate may be subject to a dampening methodology proposed in each rate case if there proves to be significant rate period to rate period Demand Rate volatility.

6.4 Load Following and Ramping Charge

At this time BPA is not including a load following charge or ramping charge in the Tier 1 rate design. Therefore, BPA will not include a methodology for calculating a load following charge and/or ramping charge in the TRM. BPA will continue to monitor the use and amount of capacity provided for hour-to-hour ramping and within hour load following. If, in monitoring this capacity, BPA determines that an explicit charge should be developed to foster external investment and/or to address cost causation, BPA will develop the methodology and make its proposal in a future rate proceeding.

7 TIER 2 RATE DESIGN

The specific rate designs for BPA's Tier 2 rate alternatives will be determined in future section 7(i) rate proceedings. The allocation of costs to the various Tier 2 cost pools that will be associated with the rate alternatives will be guided by this TRM. The overarching principle of Tier 2 cost allocation and rate design is that each Tier 2 cost pool will not be responsible for the costs of other cost pools. Also, a fundamental principle of Tier 2 cost allocation and rate design is that the Tier 2 rates will recover the full cost of serving Tier 2 load, and that the output of Tier 1 System Resources will not be used in a manner that subsidizes the costs of Tier 2 service, as forecast in the applicable rate cases.

7.1 Overall Construct

A customer's product choice will affect the Tier 2 rate alternatives available to it. In general, a customer electing BPA as its service provider for all or a portion of its above-RHWM load is also agreeing to pay for the incremental costs of resource acquisitions and purchase power costs BPA allocates to the relevant Tier 2 cost pool selected by the customer. Tier 2 rates will be based on the cost of providing a flat annual amount of power. The Tier 2 rate alternatives currently contemplated include a Load Growth Tier 2 rate, a Short-Term Tier 2 rate, and Specific-Resource Vintage Tier 2 rates. Summary descriptions of BPA's proposed list of initial Tier 2 rate alternatives can be found in Attachment A. Over time, BPA may propose in power rate cases to update, modify, eliminate, or add to the Tier 2 rate alternatives summarized in Attachment A.

7.1.1 Timing of Notices

Every customer must determine and notify BPA by November 1, 2009, whether it will purchase power from BPA at Tier 2 rates or apply resources for its above-RHWM load for at least FY 2012 through FY 2014.

7.1.1.1 Notice by November 1, 2009

Each Load Following customer must elect how its above RHWM load will be served from FY 2012 through FY 2014. In general, its choices are: all BPA Tier 2; all non-Federal resources; or some pre-defined combination of the two (*e.g.*, the first 5 aMW of above-RHWM load served at the Short-Term Tier 2 rate and non-Federal resources covering the remainder, or vice-versa). For BPA service at Tier 2 rates, the available rate choices are: the Load Growth Tier 2 rate, the Short-Term Tier 2 rate, and the Vintage Tier 2 rate (if available by November 2009). Additionally, each Load Following customer may establish some pre-defined combination of these Tier 2 rates. A customer that elects to have its entire above-RHWM load served at the Load Growth Tier 2 rate is also eligible to participate in the Shared Rate Plan (SRP), if it makes such election by November 1, 2009.

Each Block and Slice/Block customer must elect how its above-RHWM load will be served for FY 2012 to FY 2014. Its choice is between: 1) all non-Federal resources; or 2) some pre-defined combination of the available Tier 2 rates (with a defined take-or-pay commitment) and non-Federal resources (determined annually). For BPA Tier 2-priced service, the available rate choices are: the Short-Term Tier 2 rate and the Vintage Tier 2 rate(s) (if available by November 2009). Additionally, Block and Slice/Block customers can establish some pre-defined combination of these Tier 2 rates.

7.1.1.2 Notice by September 30, 2011 (*i.e.* 3 years prior to the end of FY 2014)

Each customer must elect how its uncommitted above-RHWM load will be served from FY 2015 through FY 2019. It may choose among Tier 2 rate alternatives BPA makes available or apply a non-Federal resource.

7.1.1.3 Notice by September 30, 2016 (*i.e.*, 3 years prior to the end of FY 2019)

Each customer must elect how its uncommitted above-RHWM load will be served from FY 2020 through FY 2024. It may choose among Tier 2 rate alternatives BPA makes available or apply a non-Federal resource.

7.1.1.4 Notice by September 30, 2021 (*i.e.*, 3 years prior to the end of FY 2024)

Each customer must elect how its uncommitted above-RHWM load will be served from FY 2025 through FY 2028. It may choose among Tier 2 rate alternatives BPA makes available or apply a non-Federal resource.

7.2 Setting Tier 2 Amounts

As described in section 2.2, prior to each rate case in the RHWM Process, BPA will set customers' RHWMs and calculate each customer's above-RHWM load using forecast Net Requirements for the next Rate Period. When a customer's above-RHWM monthly load is greater than 720 MWh, BPA will require service at Tier 2 rates and/or with non-Federal resources. This above-RHWM amount is "locked-down" for the rate period. Block and Slice/Block customers will have already set its amount of above-RHWM load at the time the lock-down occurs for Load Following customers.

For example, a Load Following customer's Total Retail Load forecast is 100 aMW for both years of the Rate Period and its RHWM is 80 aMW. The customer committed to the Short-Term

Tier 2 rate for all of its above-RHWM load service; therefore, its Tier 2 billing determinant is 20 aMW for both years of the Rate Period. The customer will be billed the Short-Term Tier 2 rate for 20 aMW in every month of the Rate Period.

7.3 Cost Basis

Once Tier 2 billing determinants are known for the Rate Period (developed in the RHWM Process,) cost pools for each rate alternative will be formed and allocated costs for each cost pool will be calculated to include the following components: projected resource costs and/or projected market purchase costs, projected Resource Support Services costs (if applicable), an overhead cost adder, resource-specific actual operating costs (if applicable), risk mitigation (if determined necessary), and the costs for remarketing excess Tier 2 energy. Each Tier 2 rate alternative will have its own separate cost pool. The cost components included in each Tier 2 cost pool will be dependent upon the type of resource costs included in the pool and will be decided in the appropriate rate case.

7.3.1 Cost Component Construct

The intent in determining the costs included in individual Tier 2 cost pools is that the costs and cost of risk that each Tier 2 customer faces will be comparable to the types of costs and risks the customer would face if purchasing from an independent source.

For rate alternatives using block energy purchases from market sources, the costs allocated to the cost pool will be designed to include costs that typify a block-forward purchase at a fixed price. These types of costs include the projected cost of the energy from a market purchase, a risk component of the type that an independent source would add to cover its expected risks of

providing service at a fixed forward price, transaction costs, and a BPA overhead cost adder. *See* section 7.3.3 for the construct of the overhead cost adder.

For non-dispatchable resource rate alternatives, the costs allocated to the cost pool will be designed to include costs that typify a purchase of a non-dispatchable resource. These types of costs include the cost of the resource purchase, any RSS charges, transaction costs, and a BPA overhead cost adder. The RSS charges are the same that would be applied to a customer's purchase a non-Federal non-dispatchable resource to have the power be costed as it were delivered as a flat annual block. *See* section 7.3.2 and section 9 regarding RSS charges. See Attachment F for an example of a Tier 2 rate alternative based on a wind resource.

For dispatchable resource rate alternatives, the costs allocated to the cost pool will be designed to include costs and risks that typify a purchase of a dispatchable resource with the customer assuming the operational risks. These types of costs include projected annual fixed costs (debt service and fixed O&M) of the machine, the expected fuel and variable O&M costs of the machine based on the expected operation of the machine, a mechanism to true-up the expected fuel and variable O&M costs to actual costs, a mechanism to compensate the customer for any savings from economic dispatch of the machine including fuel remarketing proceeds, transaction costs, and a BPA overhead cost adder.

7.3.2 Resource Support Services and Environmental Attributes

Any resources acquired by BPA to serve Tier 2 loads will include appropriate RSS charges, Resource Shaping Charges (to account for the costs of converting resource output into flat annual delivery), and Resource Shaping Charge Adjustments (to recover the cost differential between planned and actual energy output) necessary to price the service as if the resource output is

serving a flat annual load. An adjustment for the Resource Support Services provided by Tier 1 System Resources to ensure energy neutrality and to compensate the Tier 1 cost pools for risk exposure incurred due to the provision of RSS will be made. This adjustment will be applied, as necessary, to resources serving Tier 2 loads and the costs allocated to the Tier 2 rate alternative for RSS will be set in each rate case. A customer purchasing under these Tier 2 rate alternatives may face adjustments to its charge each year to account for changes due to actual resource output. These services and charges are discussed in section 9.

If a particular Tier 2 cost pool includes renewable generation, but it is not a Renewable Vintage Tier 2 rate, BPA will market any environmental attributes (RECs) associated with this renewable generation and credit the forecast revenues to the relevant Tier 2 cost pool.

7.3.3 Overhead Cost Adder

Each Tier 2 cost pool will include an overhead cost adder. This adder is intended to compensate Tier 1 cost pools for the general overhead costs associated with BPA's provision of power at Tier 2 rates. In each rate case, BPA will propose a per-kilowatthour adder to be applied to all power sold at Tier 2 rates. The adder will be determined in each rate case. The adder is intended to compensate Tier 1 ratepayers for the general and administrative costs BPA incurs to provide Tier 2 services. The adder will be set at a level comparable to typical electricity broker fees rather than an accounting of BPA's actual overhead costs.

7.3.4 Risk Mitigation

In each rate case, when there is more specificity about the resource and purchase costs allocated to the various Tier 2 cost pools, BPA will assess the associated risks of the different resources associated with these costs (*e.g.*, fuel price risk), and will propose risk mitigation tools that will

be in addition to the Resource Shaping Charge Adjustment (*see* section 9.1.2). BPA recognizes it may be limited in Tier 2 rate offerings by the requirement in section 5.2 that Tier 2 risks not increase costs allocated to Tier 1, nor require enhancement of Tier 1 risk protections.

7.4 Remarketing of Tier 2 Amounts

Depending on a customer's contract type and Tier 2 service election, it may have made long-term take-or-pay commitments to Tier 2 service based on forecast load. These committed Tier 2 amounts may turn out to be greater than the above-RHWM load (not otherwise committed to be served by applying non-Federal resources) calculated for future Rate Periods. BPA seeks to enable a customer that has made a long-term take-or-pay Tier 2 commitment to have access to Tier 1 service to the maximum extent of its eligibility. To accomplish this objective, BPA will remarket committed Tier 2 amounts and credit the proceeds to the specific customer in the event a customer's above-RHWM load (not otherwise committed to be served by non-Federal resources) is less than the previously-committed Tier 2 amounts. Because Block and Slice/Block customers will have an annual net requirement calculation, BPA will annually assess the need for remarketing of take-or-pay Tier 2 commitments. In addition, BPA will remarket committed Tier 2 amounts for Load Following customers for each Rate Period to that extent that above-RHWM load does not materialize; a situation that may occur for customers making commitments to Vintage Tier 2 rate alternatives. In the appropriate rate case, BPA will establish the appropriate transaction costs to be included in the Tier 2 cost pools.

7.4.1 Calculating the Remarketed Tier 2 Proceeds

If BPA remarkets any power acquired for Tier 2 service but not taken by a customer, the forecast proceeds will be credited against the customer's monthly Tier 2 charges. The difference (could be a credit or a charge) will be assigned to the specific customer. BPA will value the remarketed

energy, adjusted for transaction costs, based on forecast Mid-C prices, or a comparable successor, for a flat annual block of power for the Rate Period, determined as follows. The market values will be determined by a survey of the price for a flat block of power for the next fiscal year. The survey will be performed by averaging each daily closing price during the July and August prior to the rate case. Transaction costs will encompass such things as broker or other marketing fees, transmission costs, transmission losses, and odd lot sizes. The forecast value of the remarketed amount will be divided by 12 and netted against each month's billed take-or-pay Tier 2 amount. The customer will still be responsible for any Resource Shaping Charge Adjustments that apply to the Tier 2 amount that BPA is remarketing. For those customers selecting the Vintage Renewable Tier 2 rate, the environmental attributes from the full amount of the take-or-pay commitment (*i.e.*, including the amount that is being remarketed) would still be transferred to the customer. An example of how to calculate remarketed Tier 2 proceeds can be found in Attachment E. This procedure will be applied whether or not BPA actually remarkets the power or uses it for its own purposes. There will be no true-up to actual revenue BPA receives for actual disposition of this power.

7.5 Provision for Additional Tier 2 Rate Alternatives

The only additional Tier 2 rate alternatives BPA expects to add to the customers' options (summarized in Appendix One) are new Specific-Resource Vintage Tier 2 rates. If BPA has been able to secure a resource in accordance with a prospectus offered to eligible customers, and if those customers agree to transfer load service from the Short-Term Tier 2 rate to the new Vintage Tier 2 rate, then that Vintage Tier 2 rate will be proposed in the next general rate case.

[this italicized paragraph is for context and will not appear in the Methodology]

Provision for Conservation Mechanisms in Lieu of Tier 2 Rate Alternatives

A customer with a RHWM less than its Net Requirement may request that BPA serve its above-RHWM load at a Tier 2 rate. In response, BPA could help the customer to procure conservation to offset its need to buy power in excess of its RHWM. The opportunities to procure conservation to the customers in lieu of more expensive incremental resource acquisitions may not always be feasible but, if such opportunities are feasible, BPA will consider the conservation as fulfilling the customer's Tier 2 obligation. Depending on the circumstances, BPA could develop programs that encourage a utility to develop conservation in amounts that reduce some, or all, of the customer's above-RHWM load. BPA would fully recover the cost of such conservation from the customer through a bilateral arrangement.

8 THE SHARED RATE PLAN (SRP)

Load Following customers will have a limited time opportunity to select the Shared Rate Plan (SRP) by November 1, 2009, if they have committed to purchase 100 percent of their above-RHWM load service at the Load Growth Tier 2 rate. Access to the SRP is limited to a number of customers whose total CHWM does not exceed 500 aMW. If there are requests for more than 500 aMW of CHWM for the SRP before November 1, 2009, BPA will stack the requests from smallest to largest. BPA will select customers starting with the smallest until the last customer selected has its entire CHWM fit within the 500 aMW limit. This stacking will exclude the largest customers from the SRP, accepting as many smaller customers as can be accommodated.

Under the SRP, each participant pays the same SRP Customer rate calculated by combining the costs and forecast billing determinants at the Tier 1 Composite rate and the Non-Slice Customer rate and the Load Growth Tier 2 rate for all participants. BPA will ensure that non-participating customers are not financially impacted by this rate option.

Based on SRP participants' individual Tier 2 amounts, BPA will determine the participants' share of Load Growth Tier 2 allocated costs for inclusion in the SRP cost pool. Added to the cost pool are the participants' share of Tier 1 Composite and Non-Slice Customer allocated costs. The SRP Customer rate is computed by expressing total SRP costs in the form of a dollar-per-one percent rate. Each participant will have a customer Shared Rate Cost Allocation (SRCA). This SRCA is calculated by taking each participating customer's forecast Net Requirement for the Rate Period divided by the sum of all participating customers' forecast Net Requirement for the Rate Period. Multiplying the result by 100 turns it into a percentage, which will be the customer's SRCA. To determine the monthly billing amount, BPA will multiply the SRCA for each participating customer by the Shared Rate Customer rate. Energy true-ups

associated with the Resource Shaping Charge Adjustment for the resources whose costs are allocated to the Load Growth Tier 2 rate pool will be shared by all participants in the SRP based on its SRCA.

The Load Shaping, Demand, and Load Following (if applicable) charges will continue to be calculated on an individual customer basis and in the same manner as they are for all Load Following customers, *i.e.*, using the TOCA. The exception to this is that there will be a special true-up for Load Shaping Charges for customers in the SRP. When individual customers annually purchase less above-RHWM power than was projected in the rate case, these customers will not keep the extra Load Shaping credit and will retain only the equivalent to what it paid for the power through the SRCA. Any excess will be returned proportionally to all customers in the SRP.

The LDD and IRM may need to be applied differently for eligible customers that participate in the SRP to ensure that they receive comparable treatment to those eligible customers that are not SRP participants. These issues will be resolved in applicable rate cases.

9 RESOURCE SUPPORT SERVICES

Resource Support Services (RSS) are provided for resources, whether Federal or non-Federal, to deem the resource suitable for serving above-RHWM load. There are three services in the RSS package. They are the Diurnal Flattening Service, Forced Outage Reserves, and Secondary Crediting Service. The following provides an overview of the products available within RSS. The design and pricing governing these products will be developed or modified in each rate case. RSS is available only to customers with a CHWM Contract.

9.1 Diurnal Flattening Service

The Diurnal Flattening Service (DFS) is a service that makes a variable or intermittent resource (that is dedicated to load) financially equivalent to a resource that generates power in a shape that is flat within the 24 HLH and LLH periods of the year. Groups of resources (*i.e.*, those whose costs are allocated to specific Vintage Tier 2 Resource cost pools or non-Federal resources serving a single customer's above-RHWM load) may be aggregated for purposes of pricing the DFS. The DFS is applied only to the variable or intermittent portion of the particular resource(s). Certain resources have firm and variable components and the service is applied only to the variable component of the resource(s).

This service will be applied to Tier 2 System Resources to flatten specific augmentation resources, and applied to eligible non-Federal resources used to serve both above- and below-RHWM load. This service, in conjunction with the Resource Shaping Charge, is consistent with Tier 2 System Resources, augmentation, and non-Federal resources serving load being benchmarked against a flat annual block.

Pricing of the DFS will consist of two charges, one for capacity and the other for energy. Determination of a resource's capacity billing determinant will be resource specific and will take into account historical scheduled generation (when historical scheduled generation is not available, BPA will use historical scheduled generation from a similar resource) and any applicable regional Integrated Resource Plans. The capacity charge will be based on the amount of capacity each resource provides relative to the amount of capacity provided if the resource produced a flat annual block of firm energy. If it is determined that the resource provides less capacity than a flat annual block, then the difference will be the billing determinant applied to the Demand Rate. If it is determined that the resource provides more capacity than a flat annual block, then there may be a credit for the difference; the credit for determining the method would be developed in applicable rate cases. Purchasing this service insures that the resource has sufficient capacity to meet BPA's flat annual benchmark above-RHWM loads.

Pricing the energy component of the DFS will reflect the difference between the energy provided by the variable or intermittent portion of a resource's hourly scheduled generation and if the resource was scheduled flat within the 24 diurnal periods of the year. BPA will use the historical hourly scheduled generation from the resource or a similar resource (if generation from the specific resource is not available) to determine the energy value difference when compared against the flat annual block of energy. The variable portion of the resource will incur an energy charge based on efficiency losses associated with an energy-supporting resource. The identification of the energy-supporting resource and the pricing associated with such a resource will be proposed and determined in each rate case.

9.1.1 Resource Shaping Charge

The customer-specific annual Resource Shaping Charge is a charge or credit that adjusts for the difference in value between a planned resource energy shape that is flat within the 24 HLH and LLH periods of the year and an equivalently sized flat annual block. For resources purchasing the DFS, the Resource Shaping Charge is applied to the 24 flat blocks. Customers applying a resource that is flat within the 24 HLH and LLH periods of the year will avoid the DFS charge but are still subject to the Resource Shaping Charge.

The rates used to calculate the resource-specific annual Resource Shaping Charge will be equal to the Load Shaping Rates (*see* section 6.2.)

The annual Resource Shaping Charge will be calculated once each Rate Period and will be billed on a flat monthly basis (rate period charge divided by 24). The resource's firm and flat HLH and LLH output (or expected output if purchasing DFS) will be compared to the shape of an equivalently sized flat annual block. This comparison is made to meet BPA's flat annual benchmark requirement.

The Resource Shaping rate will be applied to the difference between a flat annual block and the resource's expected monthly/diurnal firm output (flat annual block minus resource's firm or expected output). This calculation can be a positive or negative number. If the resource produces (or is expected to produce, if purchasing DFS) less energy than the flat block during any of the 24 diurnal periods of the year, this will result in a positive billing determinant (charge). This charge will be the forecast cost of purchasing power to make up the difference between the diurnally flat energy amount and a flat annual block. If the resource produces more energy than the flat block during any of the 24 diurnal periods of the year, this will result in a negative billing determinant (credit). This credit will be based on the forecast price of power for

each diurnal period when the diurnally flat energy amount is greater than a flat annual block. The calculated billing determinants for HLH and LLH energy will be applied to the corresponding Resource Shaping rate, which will be equal to the Load Shaping rate (*see* section 6.2). The sum of the products of the diurnal billing determinants times the appropriate Resource Shaping rates will equal the resource-specific annual Resource Shaping Charge.

9.1.2 Resource Shaping Charge Adjustment

This adjustment is applicable only to resources purchasing the DFS. The DFS is an energy-neutral service that requires an end-of-month adjustment when a resource produces more or less energy than what was expected when the service was priced. For each monthly/diurnal period, the Resource Shaping Charge Adjustment will compare the expected energy (as forecast in the rate case) to the actual monthly generation of the resource. If a resource produces more than its forecast energy, then a credit is due to account for the excess generation. Conversely, if a resource produces less than its forecast energy, then a charge is due to account for the under-performance. The rates applied to the difference between forecast generation and actual generation will be the forecast market prices used for the Resource Shaping Charge and the Load Shaping Charge. The Resource Shaping Charge Adjustment will be computed and charged or credited on the customer's monthly bill.

9.2 Forced Outage Reserves

Forced Outage Reserves (FOR) service from Power Services supplements Operating Reserves Services provided under the Open Access Transmission Tariff. FOR may be called on when Operating Reserves expire. FOR will also be provided when there is a need to shut down a resource due to an imminent failure that could lead to a forced outage; or a need for unplanned maintenance. *(Unplanned maintenance needs further definition.)*

For resources that have a firm component in its expected output, the quantity of FOR capacity needed to be purchased will be the nameplate capacity minus any capacity purchased in the DFS multiplied by the machine forced outage rating, as determined in the contract providing FOR. The charge will be the monthly FOR capacity multiplied by the Demand Rate for each month of the Rate Period. The sum of these monthly charges will be divided by the months in the Rate Period to get a monthly charge that will be applied to the customer's bill each month.

Forced Outage Reserves Energy (FORE) is energy delivered when the FOR service is requested. There will be an annual energy limit, in megawatthours, defined as the machine forced outage rating multiplied by the expected annual energy output in megawatthours multiplied by 2. There will be a commitment period energy limit defined as the machine forced outage rating multiplied by expected annual energy output in megawatthours multiplied by the years in the commitment period. If the limits are exceeded, the FOR service will be repriced to accommodate additional energy deliveries. The power provided shall be charged for the first day at the higher of the hourly Dow Jones Mid-C price, the Cal-ISO hourly price plus all take-out costs and applicable transmission adders, or the applicable Load Shaping rate, as defined in the GRSPs. For the subsequent days, the price will be the average of the applicable Mid-C daily HLH or LLH price for firm power for the month multiplied by a percentage (as determined each rate case) to account for transaction costs.

9.3 Secondary Crediting Service

Secondary Crediting is available for Load Following customers and allows them to dedicate the entire output of an "existing" metered or scheduled hydro resource (either dispatchable or non-dispatchable, as long as it has both a firm critical component *plus* a secondary energy

component) to load. This service is currently intended to apply to hydro resources but could apply to other resources if secondary energy is established for them. Customers will get a credit against its PF rate charges for the amount of secondary energy applied to its load. This credit will be calculated using a HLH/LLH weighted daily average prices for the month on the Dow Jones Mid-C Index (or other replacement index adopted in a 7(i) rate proceeding) reduced by a percentage (as determined in each rate case) to account for transaction costs.

10 OTHER RATE DESIGN

10.1 Low Density Discount

The Low Density Discount (LDD) will continue under tiered rates. No LDD will be paid on above-RHWM load in order to allow a level playing field in choices between BPA service and self-supply. However, the Tier 1 LDD discount will be adjusted based on the customer's Total Retail Load such that the utility gets approximately the same benefit it would have received under melded rates.

BPA will continue to propose a LDD in its rate cases unless a prior rate case eliminates the LDD. Section 7(d)(1) of the Northwest Power Act authorizes the Administrator to provide a discount, to the extent appropriate, to customers whose retail rates have been adversely affected by low system densities. The Administrator has discretion to establish the criteria under which the LDD is offered and to determine whether it is appropriate to offer an LDD based on the criteria adopted.

BPA will make the following three changes to the LDD for the post-2011 period:

Definition of Consumers

Following is the definition for Consumers in the LDD section of the FY 2012 General Rates Schedule Provisions (GRSPs), which will be effective October 1, 2011:

> Consumers will be the number of consumers, by classification, having a current service connection in December of each year. Residential consumers (seasonal and non-seasonal) should be counted on the basis of the number of residences served. If one meter serves two residences, then two consumers should be

counted. If a water heater is metered separately from other appliances on the same premises, the water heater load will not count as a separate consumer.

Security or safety lights, billed to a residential customer, will not be counted as an additional consumer.

Seasonal consumers expected to resume service during the next seasonal period will be counted during off-season periods as well.

A residence and commercial establishment on the same premises, receiving service through the same meter and being billed under the same rate schedule, would be classified as one consumer based on the rate schedule. If the same rate schedule applies to both the residential and the commercial class, the consumer should be classified according to the principle use.

Consumers for Public Street and Highway Lighting should be counted by the number of billings, regardless of the number of lights per billing.

10.1.1 Adapting the LDD to Tiered Rates

The LDD will be based on a customer's Total Retail Load minus Existing Resources. The base discount will be determined using the adjusted TRL and the LDD Percentage Discount Table, as published in the applicable GRSPs. To reflect an increase or decrease in a customer's adjusted TRL, the percentage discount will be adjusted for application to the customer's bill. For example, if a customer is eligible for an LDD of 5 percent on its adjusted TRL, and its RHWM is 10 aMW, then the customer would have its LDD percentage adjusted upward to 5.5 percent. The

7 percent cap would also be adjusted upward by the same amount for affected customers. All other GRSP criteria to qualify for the LDD would be retained, as modified in section 0. The formula used to calculate the applicable LDD percentage to be applied to the customer's bill during the Rate Period is:

$$applicableLDD = eligibleLDD \times \frac{adjTRL}{RHWM}$$

where:

eligibleLDD = the LDD percentage indicated by the customer's eligibility factors;

adjTRL = the customer's Total Retail Load adjusted by Existing Resources; and

RHWM = the customer's Rate Period High Water Mark.

This applicable LDD percentage would apply to all BPA Tier 1 purchases (customer charge, load shaping and the demand charge) of the customer receiving the LDD. The LDD costs will be allocated to all PF Tier 1 purchasers (including PF Exchange purchasers). This adjustment would apply to LDD-eligible Slice customers in a similar manner. The eligibility requirements of C/M and K/I will still be calculated and may result in customers now eligible for the discount being disqualified in the future.

10.1.2 Calculation of LDD for Slice

A Slice customer will have its LDD dollar benefit calculated as though they were Load Following customers, with the exception that a discount on the Load Shaping charge will not be included in the benefit. Using the previous fiscal year's load data, an annual Low Density Discount dollar benefit amount will be calculated. This amount will be divided by twelve to derive a monthly LDD credit. This monthly LDD credit will be applied to the customer's monthly power bills. There will be no separate Slice and Block LDD benefits calculated. The LDD percentage will be adjusted for load growth as described in section 10.1.1 above.

10.2 Irrigation Rate Mitigation

A discount for irrigated loads will continue under tiered rates. Eligible irrigation loads will not increase during the term of this TRM. The discount will be a fixed percentage discount on the Tier 1 rate. Since irrigation loads do not increase, there is no Tier 2 service available to eligible loads.

BPA will continue to propose Irrigation Rate Mitigation (IRM) in BPA's wholesale power initial rate proposals in the form of a fixed percentage discount unless a prior rate case eliminates the IRM. In these initial rate proposals, BPA will propose that the fixed percentage will be the effective reduction in the melded, weighted average of the spring and summer rates caused by the irrigation rate mitigation product in the average FY 2007-2009 PF rates (it is estimated to be in the 30-34 percent range.) This discount will be seasonally available to qualifying loads during May, June, July, August and September.

Regional Dialogue contracts will include a provision acknowledging the IRM as a rate adjustment, the terms of which will be determined in rate proceedings and subject to BPA's GRSPs. Qualifying irrigation loads will also be specified in Regional Dialogue contracts. A section 7(i) rate proceeding would establish the amount of an irrigation discount applied to qualifying irrigation loads starting with the FY 2012 rate period. Any discount, if /adopted by the Administrator, will be included in BPA's General Rate Schedule Provisions (GRSPs) for BPA's FY 2012 Tier 1 power rates or successor rates. All costs of IRM will be allocated to all PF Tier 1 purchasers (including PF Exchange purchasers).

BPA will propose the following basis for IRM eligibility in the FY 2012 GRSPs, which will be effective October 1, 2011. To qualify for the IRM discount, the customer must meet one of the following criteria:

(a) Participated in BPA's FY 1997-2001 Summer Seasonal Product.

(b) Participated in BPA's FY 2007-2011 Irrigation Rate Mitigation Product.

(c) The purchaser's average annual irrigation rate schedule sales must be greater then 7,500 MWh in the months of May thru September for FY 2002-2004.

(d) A minimum of 5 percent of the annual total retail load sales must have been billed under the purchaser's irrigation rate schedule.

For a Slice/Block customer, the percentage reduction will be applied to the lesser of its monthly block purchased at Tier 1 rates, or the qualifying irrigation kilowatthours specified in its contract. If there is a reduction of the FCRPS that results in the Slice customer's Block reducing the IRM benefit, and that otherwise would not have reduced/impacted the benefit, the Contract FY 2012 Block amount will be used when comparing whether the Block or eligible kilowatthours will be the limiting amount when determining eligible IRM benefits. No other charges or billing determinants will be affected.

There will be a true up process at the end of the irrigation season to ensure that the customer demonstrates the full amount of irrigation load. If a customer's May to September measured irrigation load is less than the amount of load eligible for mitigation, a true up will be owed to BPA at end of the irrigation season. The details and requirements of the true up will be developed in the applicable rate cases and included in the GRSPs for each applicable Rate Period.

BPA will require participating customers to implement cost-effective conservation measures on eligible irrigation systems in its service territories. The conservation measures may be eligible for future BPA conservation programs, although the eligibility of particular measures and the amount of BPA support have not been determined.

10.3 Direct Service Industry Service

BPA is exploring a number of approaches intended to provide service benefits to the DSIs after 2011, including a financial mechanism similar to the existing FY 2007-2011 DSI contract that provides the Region with known, capped costs. The financial types of costs will be allocated as BPA program costs (*i.e.*, section 7(g) costs.)

Also, BPA reserves the option to provide some level of physical power to the DSIs under a Regional Dialogue contract. If BPA were to make such a sale, it might be necessary for BPA to purchase augmentation as described in section 3.2.7. These system replacement costs will be allocated to Tier 1 as FBS costs. This power sale would be priced at the Industrial Firm Power (IP) rate in accordance with section 7(c). BPA does not intend to tier the IP rate, but it is not prohibited by this TRM.

10.4 7(b)(2) Rate Test

No changes are proposed to the section 7(b)(2) rate test to accommodate tiered rates. The rate test will use all PF loads, Tier 1 and Tier 2, in the conduct of the test. The 7(b)(2) rate test will be performed in accordance with the then-current Section 7(b)(2) Legal Interpretation and Section 7(b)(2) Implementation Methodology. Under tiered rates, the rate test will use aggregate rates that combine all forecast costs and loads of Tier 1 and Tier 2.

11 APPROVAL AND DURATION OF THE TRM

Except as it is subject to change pursuant to section 12 and 13, this TRM shall be effective October 1, 2008 through September 30, 2028, and shall apply to power sales specified in herein for the period October 1, 2012 through September 30, 2028.

In the event that the Federal Energy Regulatory Commission (FERC) approves this TRM for a period less than through September 30, 2028, then BPA will, prior to the expiration of the then-effective TRM effective period, 1) propose continuation of the TRM in a hearing conducted pursuant to section 7(i) of the Northwest Power Act or its successor, and 2) thereafter resubmit the TRM to FERC for approval through September 30, 2028. References in section 12 and 13 to the TRM are to the TRM as approved by FERC.

12 CRITERIA AND CONDITIONS FOR TRM CHANGE OR RE-OPENING

BPA reserves the right to change the TRM only in accordance with the criteria and conditions set forth in this section 12 and with the applicable process set forth in section 13. Reference here and elsewhere to a "change" to the TRM means a change in the actual language of the TRM; it does not refer to questions of interpretation or implementation of the TRM. When a matter is not specifically addressed in the TRM, BPA may take actions if necessary, to interpret or implement the TRM. These actions are subject to the procedures set forth in section 13.

While it is BPA's intent to structure a durable commercial relationship through this TRM and customer contracts based on existing statutory requirements, BPA does not warrant or represent that the TRM or contracts are immune from subsequently enacted legislation, or that the TRM or contracts are immune from costs imposed by court order or agency regulations of a general and public nature.

12.1 Changes to TRM to Ensure Cost Recovery or Comply with Court Order

BPA reserves the right to change any part of this TRM if the Administrator has determined in accordance with the applicable procedures set forth in section 13 that BPA cannot timely and reasonably recover its costs without the changing the TRM or that a change to the TRM is necessary to effectively comply with a court ruling.

12.2 Provisions of the TRM that may be Changed Only to Ensure Cost Recovery or Comply with Court Order

The provisions of the TRM identified below cannot be changed except and unless the Administrator determines in accordance with the procedures set forth in section 13 that BPA cannot not otherwise timely and reasonably recover its costs or that the change is necessary to effectively comply with a court ruling:

The methodology used to determine CHWMs and RHWMs as defined in section 2.1 and 2.2 except in those instances the TRM specifically provides for in sections 2.1 and 2.2.

(a) The basic Tier 1 rate design described in section 6, consisting of:

(i) the concept of three Tier One Cost Allocation (TOCA) customer charges: Composite, Slice and Non-Slice;

(ii) the development of a Load-Shaping Charge for customers purchasing Block or Load-Following products; and

(iii) Demand Charge billing determinate that include a Contract Demand Quantity (*i.e.* "grand fathered" demand) as set forth in section 6.3.

(b) The establishment of Tier 2 rates, as set forth in section 7, that reflect the incremental costs of resource acquisitions and purchases BPA must make to serve its load obligation above the customers' RHWM.

(c) Cost allocation criteria for allocating costs between Tier 1 and Tier 2 rates, and among Tier 2 rates, as set forth in section 4.

12.2.1 The general identification of cost categories and their association with Tier 1 or Tier 2 as specified in section 4 will not change – (*i.e.*, no allocation of Tier 2 costs to Tier 1 for recovery or vice-versa).

12.2.2 Before proposing any change in the TRM to ensure timely and reasonable cost recovery, BPA will take the following steps in addition to the process set forth in section 13:

12.2.3

(a) To the extent possible make reasonable efforts to recover the cost from the party(s) that would otherwise be responsible for it, including making demand on any available credit support;

(b) To the extent possible, BPA will make reasonable efforts to reduce BPA costs so as to offset the cost that would otherwise occasion the need for a change in the TRM;

(c) If the cost recovery problem is occasioned by the design of the TRM, BPA will convene a public meeting with customers and interested third parties to discuss alternatives to change of the TRM; and

(d) After taking such steps, BPA will issue a report to customers and third parties regarding the efforts, including those listed (a-c) above, that the Administrator has taken before resorting to a change in the TRM, as well as why the set of safeguards BPA followed when entering identified transactions (*e.g.*, service at a Tier 2 rate) were 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 recover costs and timely repay the U.S. Treasury.

12.3 Lock-in for Contract Term

With the exception of TRM changes that are constrained by section 12.3 or reserved by section 12.4, BPA retains the discretion to, in accordance with the applicable procedures of either sections 13.2 or 13.3 to change the TRM to address or avoid unintended consequences that put at risk the policy goals underlying the TRM. Only after BPA establishes that: 1) the change will avoid significant harm due to consequences not anticipated when the TRM was put in place; and 2) the harm avoided outweighs any harm created by the change may the change be proposed. If BPA seeks to propose, or a customer or interested third party requests, a change covered by this section, such proposal or request may only be made every four years after FY 2010 (*i.e.*, FY 2014, FY 2018, or FY 2022.)

12.4 Reserved for Change

The Administrator reserves the discretion he or she otherwise possesses under law to make changes to the TRM regarding the following, consistent with the procedures of section 7(i) of the Northwest Power Act or its successor:

- 12.4.1 Calculation of actual rate levels.
- 12.4.2 Any rate issues not addressed in this TRM.
- 12.4.3 Any rate issues specifically identified in this TRM that are specifically reserved for determination in a future 7(i). These include, but are not limited to:
  - 12.4.3.1 Rate treatment for customers that execute Regional Dialogue Contracts without a CHWM (*see* section 2.5)
  - 12.4.3.2 Forecast of Tier 1 System Resources (*see* section 3.1); forecasts of augmentation of Tier 1 System Resources (see section 3.2); forecasts of Balancing Power Purchases (*see* section 3.3)
  - 12.4.3.3 Allocation of costs consistent with section 4.2 and the Cost Allocation Table
  - 12.4.3.4 Risk mitigation (consistent with section 5)

12.4.3.5 Development of system shaped load for each customer (*see* section 6.4)

12.4.3.6 Determination of costs adder to Tier 2 cost pools (*see* section 7.3.3)

12.4.3.7 Design, pricing and application of RSS rate (*see* section 9)

12.4.3.8 Possible development of a Load Following Charge (*see* section 6.4)

12.4.3.9 Possible development of a Ramping Charge (*see* section 6.4)

12.4.3.10 Irrigation Rate Mitigation true-up (*see* section 10.2)

12.4.3.11 Application of section 7(c) of the Northwest Power Act (*see* section 10.3)

12.4.3.12 Application of section 7(b)(2) of the Northwest Power Act (*see* section 10.4)

12.4.3.13 Rates for New Publics (*see* section 10.4)

12.4.4 Development of charges for capacity

If and once the changes are made, the Administrator will indicate whether the resulting change is thereafter subject to section 12.1, 12.3, or 12.4.

13 PROCESS, REMEDIES AND DISPUTE RESOLUTION

13.1 Process Generally Applicable to Any TRM Change

No change to the TRM may be made without complying with the procedural requirements of section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act or its successor.

In the event that this TRM provides that an input to establishment, administration or implementation of the TRM shall be as determined pursuant to contract or administrative process other than a rate or rate implementation process, then any dispute concerning determination of that input shall not be subject to any of the procedures of this section 13: These inputs include, but are not limited to: CHWM Process and results, and RHWM Process and results.

13.2 Process for Any Changes to TRM Other Than a Reserved Change Under Section 12.4

13.2.1 No change to the TRM other than a reserved change under section 12.4 may be made by BPA without complying with the procedural requirements of this subsection. These include:

13.2.2 Publication in the Federal Register of a notice initiating a section 7(i) proceeding involving a proposed change to the TRM.

(a) Unless otherwise already directed to do so by BPA, the rate case Hearing Officer is empowered and required to determine, upon written petition by any rate case party filed within 10 working days after submission of BPA's initial case, based on a preponderance of the evidence:

(i) whether a matter proposed by BPA is a change in the TRM, and if so

(ii) whether the change is one other than a reserved change under TRM section 12.4, and if so

(iii) whether the proposed change is prohibited or allowed by section 12.2 or section 12.3.

The Hearing Officer is further empowered to establish and employ such procedures as deemed necessary or appropriate, consistent with the rate case schedule, to efficiently, fairly and impartially make such determinations. The decision of the Hearing Officer shall be based upon a consideration of the record on the issues, and it shall include findings of fact and conclusions of law, with reasons and bases therefore, upon each material issue of fact, law, or discretion presented on the record. The Hearing Officer may at any time render an accelerated decision in favor of a party as to any or all parts of the issues, without further hearing or upon such limited additional evidence, such as affidavits, or briefing as he may require, if no genuine issue of material fact exists and a party is entitled to judgment as a matter of law.

(b) The Hearing Officer's determinations will be binding on, and adopted by, the Administrator unless BPA or a party has, within five (5) working days of the Hearing Officer's decision, petitioned the Hearing Officer for a mini-trial before the Administrator. If such a petition is timely made, the Hearing Officer shall expeditiously schedule, consistent with the rate case schedule, a mini-trial before the Administrator.

(c) A mini-trial to the Administrator shall be a part of the rate case, shall be presided over by the Hearing Officer, and shall consist of the following:

(i) Parties shall file statements of position that summarize their arguments why the Hearing Officer's decision should be upheld or reversed, whether in whole or in part. The Hearing Officer shall encourage parties with like positions to consolidate their submissions.

(ii) Oral presentations, not to exceed two days in total, shall be scheduled before the Administrator. The order of presentation shall be the Hearing Officer, parties in opposition to the Hearing Officer's decision, parties in support of the Hearing Officer's decision, and, any rebuttal by the Hearing Officer. 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 presenters that he deems appropriate.

(iii) At the conclusion of the oral presentation and on the same day, the Administrator shall state his tentative decision unless the Administrator cannot then so state.

(iv) Within five (5) working days of the oral presentations, the Administrator shall provide the Hearing Officer a written statement that he either adopts or does not adopt the Hearing Officer's decision. If the Administrator adopts the Hearing Officer's decision, that shall be conclusive for remaining purposes of the rate case hearing. If the Administrator does not adopt the Hearing Officer's decision, the Administrator shall summarize the basis for the decision, but may elect to change the decision at the conclusion of the rate case hearing in the Administrator's Record of Decision. In such instances, the Administrator must provide a reasoned basis for such a determination.

13.3 Process Applicable to Alleged BPA TRM Change Outside a Rate Case

13.3.1 In the event a preference customer believes that BPA action changes or constitutes an attempt to change the TRM outside a rate case held pursuant to section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act or its successor, it shall promptly, but no later than five (5) working days after it learns of BPA's action, notify BPA in writing of its belief and the general basis for its belief. BPA will notify customers and interested parties of the notice within five (5) working days of its receipt, shall, if possible, provide a summary of its position why the action is not a change or attempted change, and shall promptly convene a public meeting with customers and interested third parties to discuss the notice and BPA's action.

13.3.2 If, within five (5) working days after the conclusion of the public meeting held pursuant to section 13.3.1, no preference customer group (PPC, NRU, PGP, WPAG, Slice Customers) notifies BPA that it believes BPA's action changes or constitutes an attempt to change the TRM, then BPA shall proceed in the ordinary course. This does not preclude any individual customer from seeking judicial review of BPA's final action, but does constitute an election by each major preference customer group not to seek judicial review.

13.3.3

(a) If, within five (5) working days after the conclusion of the public meeting held pursuant to section 13.3.1, the preference customer group (PPC, NRU, PGP, WPAG, Slice Customers) notifies BPA that it believes BPA's action changes or constitutes an attempt to change the TRM, then BPA shall refer the matter to a third-party neutral for a binding decision on the matter.

(b) The third-party neutral shall be selected at random from a roster of neutrals maintained by BPA, and selected by BPA in consultation with major preference customer group representatives, for the purpose of determining disputes whether a BPA action is a change or attempted change in the TRM.

(c) Within 5 working days of announcement of the neutral's appointment, any major preference customer group may submit a written submission to the neutral, BPA, and other major preference customer groups in support of its position that BPA's action constitutes a change or attempted change in the TRM. BPA, and any major preference customer group that so elects, shall within ten (10) working days thereafter submit a written submission to the neutral, BPA, and other major preference customer groups in support of its position that BPA's action does not constitute a change or attempted change in the TRM. No written submission shall exceed fifty (50) double-spaced pages (12 point font; 26 lines, except for single-spaced quotes), together with exhibits not in excess of one hundred (100) pages.

(d) Within five (5) working days of receipt of the last of the written submissions made pursuant to section 13.3.3.c, the neutral shall notify the parties whether the neutral wishes to hear argument or otherwise discuss the parties' submissions and, if so, the date for the hearing, provided it shall occur within ten (10) working days.

(e) In the event the neutral has not set a hearing pursuant to section 13.3.3.d, the neutral shall, within ten (10) working days of the last of the written submissions pursuant to section 13.3.3.c, issue a written determination whether BPA's action constitutes a change or attempted change in the TRM. In so doing, the neutral shall accord substantial deference to the Administrator's determination that the action does not constitute a change or attempted change in the TRM.

(f) In the event the neutral has set a hearing pursuant to section 13.3.3.d, the neutral shall, within ten (10) working days after the hearing, issue a written determination whether BPA's action constitutes a change or attempted change in the TRM. In so doing, the neutral shall accord substantial deference to the Administrator's determination that the action does not constitute a change or attempted change in the TRM.

13.3.4 The decision of the neutral issued pursuant to section 13.3.3.e or 13.3.3.f shall be binding all preference customer groups, and shall be binding on and accepted by the Administrator. This does not preclude any individual customer from seeking judicial review of the Administrator's final action, but does constitute an election by each major preference customer group not to seek judicial review of BPA's final action. If the neutral determines that BPA's action constitutes a change or attempted change in the TRM, the change may not be made by BPA without complying with the procedural requirements of section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act or its successor, and the procedural requirements of section 13.2.

13.3.5 If prior to or during the process set forth in section 13.3.1-3 BPA has taken the action that the neutral subsequently determined pursuant to section 13.3.3.e or 13.3.3.f constitutes a change or attempted change in the TRM, BPA shall take all actions necessary to restore the *status quo ante* before the change.

13.4 Process Applicable to Disputes Over Implementation or Interpretation of the TRM During the Rate Case

Disputes over implementation or interpretation of the TRM during the rate case shall be subject to the Procedures Governing BPA Rate Hearings, 51 Fed. Reg. 7611 (March 5, 1986) or its successor.

13.5 Process Applicable to Disputes Over Implementation or Interpretation of the TRM During the Rate Case

13.5.1 Threshold & Qualification

(a) The procedures of this section 13.5 apply to disputes over the Administrator's determination, interpretation or application of the TRM outside the rate case that has an impact on a customer equal to or in excess of $__ million (hereafter referred to as a TRM Dispute). The fact that Administrator's determination, interpretation or application of the TRM outside the rate case has impacts on customers that aggregate to equal or in excess of $__ million does not make the matter a TRM Dispute subject to the procedures of this section 13.5. When a dispute over the Administrator's determination, interpretation or application of the TRM outside the rate case has an impact on a customer less than $__ million, BPA and the customer may agree to utilize some or all the procedures of this section.

(b) Notwithstanding the timelines set forth in this section, if more than one customer has the same or similar TRM Dispute with BPA, and the TRM Dispute satisfies the threshold set forth in section 13.5.1.a above, then the TRM Disputes should, if reasonably possible, be consolidated for purposes of this section. Such consolidation may warrant revision of timelines set forth in this section. Consequently, the parties shall make good faith efforts to decide upon reasonable revisions to the timelines, and their agreement on such timelines shall prevail over contrary timelines in this section.

13.5.2 Dispute Facilitation Process

(a) Condition To Non-Binding Arbitration or Third-Party Neutral Determination of TRM Dispute

As a condition to, and prior to initiating, any permissible dispute resolution regarding a TRM Dispute, the customer(s) shall first utilize a twenty (20) day discussion period to conduct the Executive Facilitation Process (EFP) to attempt to resolve the TRM Dispute. No such TRM Dispute can be raised in dispute resolution that has not been subjected to the EFP, unless otherwise agreed to in writing by BPA and the customer. In no case can such TRM Dispute be raised in dispute resolution, whether judicial or non-judicial review, other than by way of the non-binding arbitration process or a petition for review by the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit"), each as provided for in this section 13.5.

(b) Conduct of EFP

(i) Representatives to the EFP shall include: 1) for BPA: the General Counsel; Power Services VP or Senior VP; and the Manager for the particular matter; or any of their designees, who shall designate a chief BPA representative (BR); and 2) for the customer: any Assistant General Manager or Deputy Superintendent; legal counsel; designated utility staff; or any of their designees; who shall designate a chief customer representative (CR) for the process.

(ii) BPA or the customer shall initiate the EFP at such point as either one believes further discussions at the staff level are no longer productive. The customer shall notify the Senior Vice President of Power Services or its successor position in writing of its decision to invoke EFP, and BPA shall notify the CR in writing of its decision to invoke EFP. The EFP consideration period for the above-referenced representatives'

meetings shall be ten (10) days, and shall commence upon the first day following the notice to BPA or the customer, as the case may be. The EFP consideration period may be longer or shorter if the BR and CR agree in writing.

(iii) The representatives shall meet in Portland, OR. (or such other mutually agreeable location), and consult in good faith in an effort to resolve the TRM Dispute. In preparation for the EFP meetings, the BR and CR shall encourage BPA and customer staff to meet and identify TRM Dispute issues that remain outstanding.

(iv) In the event the representatives' EFP efforts are unsuccessful, the CR may request, and the Administrator shall agree, to meet on the unresolved TRM Dispute within the time remaining in the EFP period or, if less than ten (10) business days remain in it, within the next ten (10) business days unless the BR and CR agree upon a different time. At the conclusion of the process, the Administrator and the customer shall issue an agreed-upon joint statement that lists the resolved and unresolved TRM Disputes or parts thereof ("Joint Statement.") If, at the conclusion of that process, there are no unresolved TRM Disputes, the Administrator shall issue a final decision reflecting the agreed-upon resolutions of the TRM Disputes, and BPA and the customer agree to be bound by the resolution of such TRM Disputes unless BPA's decision is reversed on appeal by a third party to the United States Court of Appeals for the Ninth Circuit. If unresolved TRM Disputes remain in dispute at the conclusion of the process, then the Administrator shall issue a draft report on the unresolved TRM Disputes and any resolved TRM Disputes as set forth on the Joint Statement within ten (10) business days, setting forth the Administrator's rationale for the resolutions of the resolved TRM Disputes and for the Administrator's proposed resolution of the unresolved TRM

Disputes. The Administrator shall not issue a final decision until the period for initiating arbitration has expired. The customer shall not be bound by, or in any way deemed to have agreed to, the Administrator's rationales set forth in the draft report. If arbitration is not initiated by the CR within the time permitted for such action under this section 13.5, the Administrator will issue a final decision that adopts the draft report as final. If arbitration is initiated by the CR within the time permitted for such action under this section 13.5, then the Administrator will not issue a final decision until the conclusion of the arbitration process as specified in section 13.5.2.b.(i), and the dispute resolution process outlined in section 13.5.3 shall apply.

13.5.3 Arbitration

(a) Condition To Petition for Review

In the event the customer elects to seek arbitration of any unresolved TRM Dispute (hereafter referred to as a "Disputed Matter"), it must initiate arbitration by notifying the Administrator in writing of its election within ten (10) days of the Administrator's issuance of the draft report pursuant to section 13.5.2.(iv) above. However, if the CR notifies the Administrator that the customer waives its right to arbitration, the Administrator shall issue a final decision, which may then be timely appealed to the United States Court of Appeals for the Ninth Circuit.

If one or more of the Slice Customers initiates arbitration of any Disputed Matter(s) pursuant to this section, then no Slice Customer or any other party to the arbitration may file a petition for review of any such Disputed Matter(s) during the pendency of the arbitration.

(b) Scope of Arbitration

The scope of arbitration shall be confined to a determination whether the Administrator's determination of the Disputed Matter is a reasonable one consistent with the TRM. This does not allow the arbitrator to substitute his or her judgment of what the most reasonable determination is, but requires the arbitrator to determine whether the Administrator's determination is a reasonable one. In making such determination, the arbitrator shall make such findings of fact and determinations of law as he or she deems appropriate, and shall, if there be question about it, declare the rights and duties of the parties. The agency administrative record developed pursuant to section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act in connection with establishment of the TRM may be looked to for evidence relevant to consistency, and no party may introduce and the arbitrator shall not consider any evidence of contract negotiations to show contractual intent with respect to the Disputed Matter.

(c) Conduct of Arbitration

(i) Except as set forth in this section 13.5, the Administrator shall establish in consultation with customers and interested third parties the procedures and limitation for the conduct of arbitration under this section 13.5.3.c (hereafter referred to as the TRM Arbitration Procedures) (NOTE: It is BPA's expectation that a list of pre-approved individuals available to serve as neutrals will be maintained for this purpose. The process will be designed in a way so that, if reasonably possible, the process is appellate-like [no depositions, discovery, cross-examination] and reasonably quick, lasting a month or less if possible. All affected parties could participate and have the opportunity to file briefs and present oral argument. However, this design may be too limiting for issues that are complicated and complex. This needs to be discussed, as do issues such as timing, burden of proof, deference, presumptions, standards the

neutral would use, and other procedural matters.) If the CR notifies the Administrator that it is initiating arbitration of a Disputed Matter, such arbitration will be conducted in accordance with, and will be subject to the limitations, set out in the TRM Arbitration Procedures unless the BR and CR agree otherwise. Unless the BR and CR agree otherwise, the arbitration shall take no more than thirty (30) days, meaning that the arbitrator's decision shall be rendered within thirty (30) days of the arbitrator's agreement to serve as the arbitrator of the Disputed Matter.

(ii) BPA customers shall be allowed to intervene and participate in arbitrations initiated pursuant to this section. BPA, the BPA customer seeking arbitration, and any BPA customer (or group of BPA customers) that has intervened in the arbitration will bear its own costs, including attorneys fees, of the arbitration. BPA shall bear all other costs of the arbitration and, as with any other cost BPA incurs, recover such costs through its rates as appropriate.

(iii) The function and scope of arbitration is as set forth in section 13.5.3.b above. Under no circumstances shall the arbitrator appointed under this section 13 issue an award granting damages to any party or specific performance against BPA or the customer, and specific performance shall not be an available remedy against BPA or the customer.

(d) Effect of Arbitration Award

(i) Within fifteen (15) calendar days of issuance of the arbitrators' decision and award concerning the Disputed Matter(s), the Administrator shall issue and provide to the customer (and any other parties to the arbitration) a final, written decision that:

1) decides the Disputed Matter(s) and explains why he accepts or rejects the arbitrator's decision and award on each of the Disputed Matters; and 2) makes final without change the disposition in the draft report of the resolved TRM Disputes.

(ii) In the event that the Administrator's decision accepts the arbitrators' decision on a Disputed Matter, then the customer and any other party to the arbitration shall be bound by the Administrator's decision on that Disputed Matter and may seek no judicial review or any relief concerning the decision on that Disputed True-Up Matter, except that any party may seek review of the arbitration upon any of the grounds referred to in the Federal Arbitration Act, 9 U.S.C. §§ 1-16 (1988).

(iii) In the event the Administrator rejects the arbitrators' decision on any Disputed Matter, any party may timely file a petition for review of the Administrator's final decision on that Disputed Matter to the United States Court of Appeals for the Ninth Circuit. Nothing in this section 13 precludes any customer that participates in, but did not initiate, the arbitration from filing a timely petition for review to the Ninth Circuit of the Administrator's final decision on the resolved TRM Disputes.

(iv) The administrative record submitted by BPA to the Ninth Circuit shall include, but not be limited to, the Slice Contract, the record of the arbitration, the arbitrator's decision, the Administrator's final decision, and any other material constituting the administrative record.

13.6 BPA Action During Pendence of Process

If prior to or during the process set forth in section 13.5 BPA has taken the action that the Administrator subsequently finally determined should not have been taken, BPA shall take all actions necessary to restore the *status quo ante* before the action. In no event shall this be construed to provide for damages or liability for loss of profits, or special, incidental or consequential damages.

14 TIERED RATES METHODOLOGY DEFINITONS

(01) "Augmentation" means BPA power purchases or resource acquisitions necessary to achieve an annual energy load-resource balance subject to the limits of augmentation established in this TRM. *See* section 3.2.

( ) "Average System Cost" or "ASC" means the rate charged by a utility to BPA for the agency's purchase of power from the utility under section 5(c) of the Northwest Power Act and is the quotient obtained by dividing contract system costs by contract system load. *See* Proposed ASC Methodology, on BPA's web page.

( ) "Average System Cost Methodology" or "ASC Methodology" means the procedures by which regional utilities will submit ASC filings to the BPA and by which BPA will review such filings.

( ) "Balancing Power Purchases" means BPA power purchases used to balance loads and resources within a year. This is contrasted with Augmentation.

( ) "Behind-the-Meter Resources" means generating resources that reside within the service area of the customer such that the output of the resource flows directly to serve customer load without flowing through a BPA meter.

( ) "Balancing Authority Area" means is the collection of generation, transmission, and loads within the metered boundaries of a Balancing Authority. The Balancing Authority maintains load-resource balance within this area. The Balancing Authority is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

( ) "CHWM Contract" means a Regional Dialogue Contract that contains a Contract High Water Mark, allowing the customer access to requirements service at tiered rates.

( ) "Composite Customer Charge" means the product of the multiplication of a customer's TOCA and the Composite Customer rate. This charge is the means of recovering the Composite Customer Charge allocated costs. *See* section 6.1.

( ) "Composite Customer Rate" means the rate that BPA charges to recover the Composite Customer Charge allocated costs. This rate is expressed in dollars-per-one percent of Tier 1 System Resources purchased. *See* section 6.1.3.

( ) "Consumer-Owned Utility" or "COU" means a municipal, public (or peoples) utility district or cooperative utility organized under state law to provide electric power service and as a non-profit entity.

( ) "Contract Demand Quantity" or "CDQ" means the historical quantity of demand that is subtracted from a customer's CSP as part of the process of determining the demand billing determinant. *See* section 6.3.1.

( ) "Contract High Water Mark" or "CHWM" means the aMW amount used to define access to Tier 1-priced power. It is equal to the adjusted historical load for each customer proportionately scaled to Tier 1 System Resources and adjusted for conservation achieved. The CHWM is specified in each eligible customer's contract. *See* section 2.1.

( ) "Cooling Degree Days" or "CDD" means a quantitative index that reflects demand for energy to cool homes and businesses. A mean daily temperature is used as the base for cooling degree day computations. Cooling degree days are summations of positive differences from the base daily temperature.

( ) "Cost Allocation Methodology" means the procedures and processes used to assign costs to various products and services. *See* section 4.2.

( ) "Cost Allocation Table" means the *pro forma* accumulation of BPA's costs which lays out the Cost Allocation Methodology of assigning costs to the proper products and services. *See* section 4.3.

( ) "Cost Pool" means a group of specific costs created by the same cost drivers and allocated to specific products or services. *See* section 4.3.

( ) "Customer" means generally an eligible Consumer-Owned Utility or Federal agency purchasing requirements power from BPA under Regional Dialogue Contracts.

( ) "Customer System Peak" or "CSP" means the customer's single highest Heavy Load Hour energy purchase from BPA during each month. *See* section 6.3.

( ) "Demand Charge" means the product of the multiplication of a customer's demand billing determinant and the Demand Rate. *See* section 6.3.

( ) "Demand Rate" means the rate charged for the demand purchased by the customer, as defined by the adjusted Customer System Peak. *See* section 6.3.2.

( ) "Direct Service Industries" or "DSIs" means an industrial customer that contracts for the purchase of power from BPA for direct consumption.

( ) "Discretionary Obligations" means obligations placed on BPA resources that are the result of power marketing decisions by Power Services.

( ) "Diurnal Flattening Service" means a service that makes a variable or intermittent resource financially equivalent to a resource that generates power in a shape that is flat within the 24 HLH and LLH periods of a month. *See* section 9.1.

( ) "Existing Resources" means those dedicated, specific customer, or retail consumer, resources or unspecified resource amounts BPA used to calculate a customer's CHWM.

( ) "Federal Columbia River Power System" or "FCRPS" means the transmission system constructed and operated by BPA and the hydroelectric dams constructed and

operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation in the Northwest. Each entity is separately managed and financed, but the facilities are operated as an integrated power system.

( ) "Fiscal Year" or "FY" means the period beginning October 1 and ending the following September 30, unless amended by Congress.

( ) "Forecast CHWM" or "FHWM" means a 2008 forecast of each customer's Contract High Water Mark and is used as preliminary planning tool. *See* section 2.1.2.

( ) "Forecast Year" means the Fiscal Year ending one full year prior to the commencement of a Rate Period (usually October 1).

( ) "Forced Outage Reserves" means an amount of peak generating capability planned to be available to serve peak loads during forced outages. A forced outage results when a component unexpectedly fails to perform its function or is shut down for emergency reasons. *See* section 9.2.

( ) "Heating Degree Days" or "HDD" means a quantitative index that reflects demand for energy to heat homes and businesses. A mean daily temperature of 65°F is the base for heating degree day computations. Heating degree days are summations of negative differences between the mean daily temperature and the 65°F base.

( ) "Investor-Owned Utility" or "IOU" means a privately owned utility organized under state law as a corporation to provide electric power service and earn a profit for its stockholders.

( ) "Irrigation Load Normalization" means the process by which the effects of a particular year's weather and other specific factors are removed from the loads of irrigated agriculture.

( ) "Irrigation Rate Mitigation" means the form of a discount by BPA to utilities that resell power to irrigators during April through October.

( ) "Load Shaping Charge" and "Load Shaping Rate" means the charge and the rate applied to the each customer purchasing the Block or Load Following products, or the Block portion of the Slice/Block product, that accounts for the costs of serving loads in a different shape than the output of the Tier 1 System Resources.

( ) "Low Density Discount" or "LDD" means the discount provided by BPA to customers whose retail rates have been adversely affected by low system densities, as authorized by section 7(d)(1) of the Northwest Power Act.

( ) "Measured Load" means the delivery on an hourly basis at the point of delivery of BPA power to a customer as measured by BPA's metering infrastructure or by the customer's metering infrastructure.

( ) "Measured 2010 Load" means the historical FY 2010 Total Retail Load of a customer as determined by its Measured Load plus the output of its Existing Resources and its market purchases, net of its wholesale sales.

( ) "Melded Cost" means the process of combining the costs of various dissimilar products or services for purposes of establishing prices that do not necessarily track the cost incurrence of the separate products or services.

( ) "Net Requirement" means the amount of federal power that a customer is entitled to purchase from BPA to serve its consumer load. A customer's net requirement is equal to the difference between its consumer firm loads and the amount of non-Federal generation and power obtained through contracts that the customer uses to serve those loads. *See* section 5(b) of the Northwest Power Act.

( ) "New Large Single Load" means a large single load as defined in section 3(13) of the Northwest Power Act and in BPA's NLSL Policy.

( ) "New Publics" means Consumer-Owned Utilities that form, or Federal agencies that apply for service, in time to be provided a CHWM in FY 2011.

( ) "New Resources" means those dedicated, specific customer, or retail consumer, resources or unspecified resource amounts applied to serve customer load after September 30, 2006, and were not used by BPA to calculate a customer's CHWM.

( ) "New Tribal Utilities" means a utility formed after October 1, 2001, by a tribal government for purposes of providing electric service to tribal consumers.

( ) "Non-Federal Power" means electric power produced at facilities not owned, operated, or contracted by BPA.

( ) "Non-Federal Resources" means the electric power capability of generating facilities or a source of electric power or capability not owned, operated, or contracted by BPA.

( ) "Non-Slice Costs" means the subset of total annual Tier 1 System Resource costs for each year of the Rate Period allocated to be collected specifically from all customers except those purchasing the Slice portion of the Slice/Block product. *See* section 4.3.3.

( ) "Non-Slice Customer Charge" and "Non-Slice Customer Rate" means the charge and rate to recover costs allocated specifically to exclude the Slice portion of the Slice/Block product, but including the Block portion of the Slice/Block product.

( ) "Northwest Power Act" means the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839, Public Law No. 96-501.

( ) "Point of Delivery" or "POD" means a point where power is transferred from a transmission provider to a customer.

( ) "Policy" means BPA's Long-Term Regional Dialogue Final Policy, published July 2007, as amended.

( ) "Power Services" means the organization, or its successor organization, within BPA that is responsible for the management and sale of Federal power from the FCRPS.

( ) "Rate Case Year" means the Fiscal Year ending prior to the commencement of a Rate Period. The Rate Case Year immediately follows the Forecast Year, and is the year in which the rate case is conducted.

( ) "Rate Period" means the rate recovery period of the relevant rate case during which the respective set of rates are in effect.

( ) "Rate Period High Water Mark" or "RHWM" means the aMW amount used to define each customer's eligibility to purchase power at a Tier 1 price for the relevant Rate Period, subject to its Net Requirement. It is equal to the customer's CHWM as adjusted for changes in the Tier 1 System Resources. The RHWM is determined for each eligible customer in the RHWM process. *See* section 2.2.

( ) "Regional Dialogue Contract(s)" means the power sales agreements for requirements purchases between BPA and customers for power service commencing October 1, 2011.

( ) "Residential Exchange Program" or "REP" means the arrangement, based on section 5(c) of the Northwest Power Act, whereby regional utilities sell BPA an amount of electric power equal to their residential and small-farm load at their average system cost in exchange for an equal amount of Federal electric power, and pass on the cost benefits to their residential and small-farm customers in the form of lower retail rates.

( ) "Residential Purchase and Sale Agreement" or "RPSA" means a contract to implement the Residential Exchange Program with a customer.

( ) "Resource Shaping Charge" and "Resource Shaping Rate" means the charge and rate that adjusts for the difference in value between a planned resource energy shape that is flat within the 24 HLH and LLH periods of the year and an equivalently sized flat annual block. *See* section 9.1.1.

( ) "Resource Support Services" or "RSS" means the services provided to resources, whether Federal or non-Federal, to deem the resource suitable for serving above-RHWM load of Load Following customers. RSS is available in some circumstances to customers purchasing other products, but the effect is somewhat different. *See* section 9.

( ) "RHWM Process" means the public process in which Rate Period High Water Marks are determined. This process includes the projection and review of customer-specific forecast Net Requirements for the Rate Period. This Process also includes the projection and review of the forecast of the output of Tier 1 System Resources for the Rate Period.

( ) "Secondary Crediting Service" means a service to allow customers to dedicate the entire output of an existing resource that has both a firm critical component plus a secondary energy component to load. *See* section 9.3.

( ) "Shared Rate Plan" means a service whereby each participating customer pays a rate calculated by combining the costs of the expected purchases at the Tier 1 Composite rate, the Non-Slice Customer rate, and the Load Growth Tier 2 rate for all participants. *See* section 8.

( ) "Slice Costs" means costs that are specifically and solely to Slice customers. *See* section 4.3.2.

( ) "Slice Customer Charge" and "Slice Customer Rate" means the charge and rate to recover costs allocated specifically to the Slice portion of the Slice/Block product.

( ) "Slice Implementation Expenses" means those costs reasonably incurred by BPA in any Contract Year for the sole purpose of implementing the Slice product, and which would not have been incurred had BPA not sold the Slice product.

( ) "Slice Percentage" means the percentage share of Tier 1 System Resources selected by the customer to purchase under the Slice portion of the Slice/Block product contract. *See* section 3.3.

( ) "Slice True-Up" or "True-Up" means the process of computing the Slice True-Up Adjustment Charge through the comparison of the forecast Composite Customer Charge allocated costs used to set the Composite Customer Rate plus forecast Slice allocated costs used to set the Slice Customer Rate with the actual Composite Customer Charge allocated costs plus actual Slice allocated costs. *See* section 5.4.

( ) "Slice True-Up Adjustment Charge" means an annual adjustment charge (increase or decrease) as determined in accordance with the Slice contract, and billed or credited to the customer in accordance with the contract. *See* section 5.4.

( ) "Subscription Contracts" means the power sales agreements for requirements purchases between BPA and customers for power deliveries commencing October 1, 2001, and concluding September 30, 2011.

( ) "Super Peak" means amount of additional capacity provided by a non-Federal resource over the amount of capacity provided by an equivalent amount of energy delivered flat across the monthly HLH period.

( ) "Tier 1 Costs" means the costs included in BPA's costs specifically allocated to be recovered by means of the sale of the output of Tier 1 System Resources through the application of Tier 1 Rates.

( ) "Tier 2 Costs" means the costs included in BPA's costs specifically allocated to be recovered by means of the sale of the output of Tier 2 Power through the application of Tier 2 Rates.

( ) "Tier 1 Cost Allocation" or "TOCA" means the percentage cost share of Tier 1 Power being purchased by the customer under its Regional Dialogue contract. See section 6.1.1.

( ) "Tier 1 Power" means the amount of Federal requirements power being sold at Tier 1 Rates.

( ) "Tier 2 Power" means, depending on the context, the amount of Federal requirements power being sold at Tier 2 Rates or the amount of Federal requirements power being sold at a specific Tier 2 Rate.

( ) "Tier 1 Rate(s)" means the rates that apply for deliveries of Federal requirements power to meet a customer's net requirement below its Rate Period High Water Mark, reflecting the cost of the existing FBS and limited augmentation amounts. See section 6.

( ) "Tier 2 Rate(s)" means the rates that apply for deliveries of Federal requirements power to meet a customer's net requirement above its Rate Period High Water Mark, reflecting the incremental costs allocated to that service. See section 7.

( ) "Tier 2 Rate Alternatives" means the various rate options available for customers to select for the purchase of Tier 2 Power. See section 7.

( ) "Tier 1 System Resources" means the following elements: 1) Federal system hydro generation for regulated and independent hydro projects that BPA markets or is contracted to market; plus 2) other Federal system resources, including non-Federally owned projects of which BPA has acquired the output, plus 3) other BPA contract purchases; less 4) other BPA contract obligations, plus 5) any augmentation to the Tier 1 System Resources; or the output of the above listed resource categories.

( ) "Tier 2 System Resources" means the specific Federal generating resources whose costs are allocated to the Tier 2 Cost Pools. *See* section 3.6.

( ) "Tiered Rates Methodology" or "TRM" means the long-term rates methodology that implements the Policy construct of tiering BPA's Priority Firm Power rates. *See* section 1.

( ) "Total Retail Load" or "TRL" means all retail electric power consumption, including electric system losses, within a customer's distribution system as adjusted for: 1) unmetered loads or generation (*see* Behind the Meter Resources); 2) nonfirm or interruptible load as agreed to by BPA and a customer; 3) transfer loads of other utilities served by a customer, and a customer's transfer loads on a utility's distribution system that is located in another Balancing Authority; and 4) losses on a customer's transmission system.

( ) "Transition Period" means the period of years (FY 2012-2014) to transition from the rate structure under Subscription Contracts to the full implementation of a tiered rates structure under the Regional Dialogue Contracts. *See* section 2.3.

( ) "Transmission Services" means the organization, or its successor organization, within BPA that is responsible for the management and sale of transmission service on the Federal Columbia River Transmission System.

( ) "Treasury Payment Probability" or "TPP" means the probability (expressed as a percentage) that BPA will be able to make all of its planned payments to Treasury in a rate period in full and on time.

( ) "Unspecified Resources" means those amounts of power declared by a customer in its Regional Dialogue Contract to serve its firm regional retail load, consistent with the Notice and Commitment Periods. The power amount is not ascribed to a particular generation resource or power contract.

( ) "Weather Normalization" means the process by which the effects of a particular year's temperatures are removed from the loads of customers.

( ) "White Book" means the Pacific Northwest Loads and Resources Study publication BPA issues each year to help plan for adequate, efficient, and reliable long-term load service for both the Federal system and the region. The White Book provides BPA's projections of retail loads, contract obligations, contract purchases, and resource capabilities over a 10-year study horizon.

14.1 Conservation Adjustment Terms To Be Defined

Since it has been decided that the conservation adjustment provisions will be moved to an appendix to this TRM, the following terms will need to be defined in that appendix:

( ) "Conservation Achieved" means cost-effective, verified energy savings that are included in the PTR system reports accepted by BPA for measures installed from October 1, 2006 through September 30, 2010 that reduce the customer's net loads placed on BPA in FY 2010.

( ) "Conservation Adjustment" means the final step taken to determine the CHWM determined by adjusting the preliminary CHWM for the Conservation Achieved.

( ) "Implementation Manual" means the *BPA Conservation Rate Credit and Conservation Acquisition Agreement Implementation Manual* (or its successor) released by BPA's Energy Efficiency organization.

( ) "Contracting Officer's Technical Representative" or "COTR" means the authorized representative of the Contracting Officer knowledgeable in the technical aspects of BPA Agreements designated in writing by the Contracting Officer.

( ) "Energy Savings" means any reduction in electric power consumption as a result of increases in the efficiency of generation, distribution or end use.

( ) "Federal Conservation Projects" means those projects conducted at facilities owned and/or operated by the United States government.

( ) "Planning, Tracking, and Reporting System" or "PTR" means the system used by utilities to report conservation achievements to the Bonneville Power Administration. It is currently hosted at http://ptr.nwcouncil.org/.

Table 2.1

Timeline for HWM, Contract, and Relevant Rate Determinations

Year	Date or marker	Event or Action	Customer/ Product Choice	BPA Providing Tier 2-priced Power?	Comments
2008	5/1/2008	Forecast CHWM determination.	All	N/A	(Forecast 2010 Total Retail Load minus 2010 Resources from Subscription divided by the sum of all 2010 Retail Load Forecasts) times Forecast 2012 Available FBS.
	12/1/2008	Contract package signed; Product selection.	All	N/A	Resource amounts for customer-owned resources are set. See II.B.10 of Policy.
2009	5/1/2009	Forecast of loads served at Tier 2 pricing for first 2yr of transition period.	Load Following	Y	2009 Forecast net reqt load minus 2009 forecast of CHWM provides commitment amount for Tier 2-priced load.
	5/1/2009	Forecast of loads served at Tier 2 pricing for 3yr transition period.	Block;Block/Slice	Y	2009 Forecast net reqt load minus 2009 forecast of CHWM provides commitment amount for Tier 2-priced load.
	11/1/2009	Commitment to buy set amount of power for 2012 and 2013 at Tier 2 pricing.	Load Following	Y	
	11/1/2009	Commitment to buy set amount of power for 2012 through 2014 at Tier 2 pricing.	Block;Block/Slice; Load Following w/ set purchases at Tier 2 pricing.	Y	
2010	7/1/2010	Rate case load forecasts for 2012 and 2013.	N/A	N/A	
	10/1/2010	Forecast of Available FBS for CHWM calculation and rate case.	N/A	N/A	**Lead time needed for posting and public process/finalization**. Forecast of 2012 FBS for CHWM is actually 2012-2013 average. Late calc date for rate case is to line up w/ Policy date of FY2010 for Avail FBS determination for CHWM.
	12/1/2010	2012-2013 rate case proposal/ Federal Register Notice.	All	N/A	
2011	6/1/2011	CHWMs calculated.	All	N/A	Date is approximate and is intended to include public process/finalization.
	8/1/2011	Rates to FERC for 2012-2013.	All	N/A	
	8/1/2011	Annual Net Requirements calculation.	All	N/A	This calculation will be governed by the Regional Dialogue-modified 5(b)/9(c) Policy and the resource declarations in the RD contract, *not* the Subscription contract.
	10/1/2011	Power delivery begins.	All	N/A	

Year	Date or marker	Event or Action	Customer/ Product Choice	BPA Providing Tier 2-priced Power?	Comments
	Before end of FY 2011	3yr notice and 5yr commitment for non-vintage power at Tier 2 rates for 2015-2019.	Block;Block Slice; Load Following w/ set purchases at Tier 2 pricing.	Y	
2012	8/1/2012	RHWMs calculated for 2014-2015.	All	N/A	(verify date).
	8/1/2012	Annual Net Requirements calculation.	All	N/A	
	7/1/2012	FBS forecast for 2014-2015 rate case and RHWM calculation.	All	N/A	
	7/1/2012	Rate case load forecasts for 2014 and 2015.	All	N/A	
	12/1/2012	2014-2015 rate case proposal/ Federal Register Notice.	All	N/A	
2013	8/1/2013	Annual Net Requirements calculation.	All	N/A	
	8/1/2013	Rates to FERC for 2014-2015.	All	N/A	
2014	7/1/2014	FBS forecast for 2016-2017 rate case and RHWM calculation.	All	N/A	
	7/1/2014	Rate case load forecasts for 2016 and 2017.	All	N/A	
	8/1/2014	Annual Net Requirements calculation.	All	N/A	
	8/1/2014	RHWMs calculated for 2016-2017.	All	N/A	(verify date).
	12/1/2014	2016-2017 rate case proposal/ Federal Register Notice.	All	N/A	
2015	8/1/2015	Annual Net Requirements calculation.	All	N/A	
	8/1/2015	Rates to FERC for 2016-2017.	All	N/A	

Table 2.2

Transparency: Sample Contract High Water Mark Report

Contract HWM Determination Process Step	Adjustments (aMW)	Comments
Measured 2010 Total Retail Load	100	Total Retail Load. Monthly aggregate LLH and HLH below.
Adjustment(s) force majeure-type events and load or data anomalies.	-7.5	2010 – Gas explosion resulted in permanent loss of load associated with Bakers Mill.
Removal of 2010 irrigation load	-2.5	
Adjustment for weather normalization	+1.5	
Return of normalized irrigation load	+3.0	
Reduction for utility's 2006 Subscription Ex. C resources for FY 2010	-40	Input to HWM process.
Utility's load eligible for determining preliminary HWM (pre-conservation adjustment)	54.5	
Sum of all utilities' load eligible for HWM determination	7300	
Available FBS/Aug. amount	7100/200	Transparency provided in FBS determination process.
Preliminary HWM	54.5	
Utility's credited conservation	3.25	
Utility's conservation-adjusted preliminary HWM	57.75	
Sum of all utilities' credited conservation	170	
Sum of all utilities' conservation-adjusted preliminary HWM	7470	
Utility's Contract HWM	**56.43**	

Table 3.1

Tier 1 System Resources

Federal System Hydro Generation	
Regulated Hydro Projects	
Albeni Falls	John Day
Bonneville	Libby
Chief Joseph	Little Goose
Dworshak	Lower Granite
Grand Coulee	Lower Monumental
Hungry Horse	Mc Nary
Ice Harbor	The Dalles
Independent Hydro Projects	
Anderson Ranch	Green Peter
Big Cliff	Green Springs - USBR
Black Canyon	Hills Creek
Boise River Diversion	Lookout Point
Chandler	Lost Creek
Cougar	Minidoka
Cowlitz Falls	Packwood
Detroit	Palisades
Dexter	Roza
Foster	
Other Federal System Resources	
Georgia-Pacific Paper (Wauna)	Condon Wind Project
White Bluffs Solar	Foote Creek 1 (BPA Share)
Columbia Generating Station	Foote Creek 2 (BPA Share)
Dworshak/Clearwater Small Hydropower	Foote Creek 4 (BPA Share)
Elwah Hydro	Klondike I
Glines Hydro	Stateline Wind Project (BPA Share)
Ashland Solar Project	

Other BPA Contract Purchases	**Contract Number**
Non-Fed Canadian Entitlement Extension Agreement Returns for Canada	
Priest Rapids CER for Canada	97PB-10099
Rock Island #1 CER for Canada	97PB-10102
Rock Island #2 CER for Canada	97PB-10102
Rock Reach CER for Canada	97PB-10103
Wanapum CER for Canada	97PB-10100
Wells CER for Canada	97PB-10101
Imports	
BCHP to BPA PwrS	99PB-22685
PASA to BPA Pk Repl	94BP-93658
PASA to BPA S/N/X	94BP-93658
PASA to BPA Xchg Nrg	94BP-93658
PPL to BPA So Idaho	89BP-92524
RVSD to BPA Pk Repl	94BP-93958
RVSD to BPA Seas Xchg	94BP-93958
RVSD to BPA Xchg Nrg	94BP-93958
SPP to BPA Harney Wells	88BP-92436
Intra-Regional Transfers (In)	
PPL to BPA SPX	94BP-94332
Tier 1 Augmentation Resources	
Existing Publics	
Klondike III (BPA Share)	
DOE Richland	
New Publics & Federal Agencies	
DSI Loads	

Table 3.1 (continued)

Tier 1 System Resources (continued)

Federal System Obligation	Contract Number
USBR Load	
BPA to BRCJ	14-03-49151
BPA to BRCJ	14-03-17506
BPA to BRCR	14-03-73152
BPA to BREG	14-03-49151
BPA to BRGC	14-03-001-12160
BPA to BROP	14-03-79239
BPA to BRSI	14-03-49151
BPA to BRSID	14-03-99106
BPA to BRSV	14-03-63656
BPA to BRTD	14-03-32210
BPA to BRTV	14-03-49151
BPA to BRYK	00PB-12132
Exports	
BPA to BCHA Can Ent	99EO-40003
BPA to BHEC Pwr S	97PB-10051
BPA to CMEC Pwr S	97PB-10055
BPA to PASA C/N/X	94BP-93658
BPA to PASA S/N/X	94BP-93658
BPA to RVSD C/N/X	94BP-93958
BPA to RVSD C/N/X	90BP-92858
BPA to RVSD Cap S	90BP-92858
BPA to RVSD Seas Xchg	94BP-93958
BPA to SMGT Pwr S	04PB-11446
BPA to SPP Pwr S	88BP-92436

Federal System Obligation	Contract Number
Intra-regional Transfers (Out)	
BPA to AVWP WP3 S	85BP-92186
BPA to PPL SNX	94BP-94332
BPA to PPL SoID	89BP-92524
BPA to PSE WP3 S	85BP-92185
Other Federal System Obligations	
1997 Pacific Northwest Coordination Agreement and associated provisions	97PB-10130
PNCA MOU (COE, Bureau, BPA)	97PB-10129
Hourly Coordination	98BP-10389
Non-Treaty Storage Agreement w/BC Hydro	DE-MS79-90BP92754
Non-Treaty Storage Agreement w/Mid-C	DE-MS79-91BP92785
Non-Power Uses Agreement	(year-to-year)
Summer Storage Agreement	(year-to-year)
Disposal Agreement Entity Agreement dated March 29, 1999	00PB-23197
Libby Coordination Agreement (LCA), Libby-Arrow Swap, and subsequent updates	99BP-22685
Arrow Local	(year-to-year)
Whitefish Operations	(year-to-year)
AOP's/Entity Agreements	(year-to-year)
DOP's/Entity Agreements	(year-to-year)
Power/Tx services MOA for generation Inputs and subsequent updates	06PB-11763
Federal system Tx losses for power deliveries	n/a
Ancillary services to BPAT	n/a
Interchange	n/a
Loop flow support	n/a
Voltage support (VAR)	n/a
Project use loads not included in USBR	n/a
Resource Support Services	n/a
Other reserve obligation	n/a

Table 4.1

Cost Allocation Table

Preliminary Allocation Table

		Year 1 Composite	Year 1 Non-Slice	Year 2 Composite	Year 2 Non-Slice
40	Transmission & Ancillary Services				
49	System Operations Efficiencies Program				
57	Marketing Sales Support				
78	Bad Debt Expense				
96	Depreciation				
105	Interest Earned on BPA Fund				

Cost Allocation Table

	COSTS AND RATE ADJUSTMENTS	Key	Year 1 Forecast	Audited Actual Data	Year 2 Forecast	Audited Actual Data	Total Rate Period
	COMPOSITE COST						
1	**Expenses:**						
2	**Power System Generation:**						
3	**Operating Generation**						
4	Columbia Generating Station (WNP-2)	F					
5	Bureau of Reclamation	F					
6	Corps of Engineers	F					
7	Long-Term Contract Generating Projects	F					
8	Long-Term Contract Generating Projects	N					
9	**Operating Generation Settlement Payment**						
10	Colville Generation Settlement	F					
11	Spokane Generation Settlement	F					
12	**Non-Operating Generation**						
13	Trojan Decommissioning	F					
14	WNP-1&3 Decommissioning	F					
15	**Contracted Power Purchases**						
16	DSI Monetized Power Sale	F					
17	PNCA Headwater Benefit	F					
18	Hedging/Mitigation (Non-Slice cost)						
19	Other Power Purchases (Non-Slice cost)						
20	Bookout Adjustments to Contracted Power Purchases	F					
21	**Augmentation Power Purchases**						
22	Tier 1 Augmentation Power Purchases	F					
23	Augmentation RSS Adder	F					
24	**Exchanges & Settlements**						
25	IOU Residential Exchange (gross costs)	X					
26	minus IOU Residential Exchange revenue	--					
27	Public Residential Exchange (gross costs)	X					
28	minus Public Residential Exchange revenue	--					
29	Other Settlements	X					
30	**Renewable Generation**	F					
31	**Generation Conservation**						
32	DSM Technologies	C					
33	Low Income Weatherization & Tribal	C					
34	Energy Efficiency Development	C					
35	Legacy Conservation	C					
36	Market Transformation	C					
37	**Power System Generation Sub-Total**						

	COSTS AND RATE ADJUSTMENTS	Key	Year 1 Forecast	Audited Actual Data	Year 2 Forecast	Audited Actual Data	Total Rate Period
38							
39	**Transmission Acquisition and Ancillary Services:**						
40	Transmission & Ancillary Services	G					
41	Third Party GTA Wheeling	G					
42	Third Party Trans & Ancillary Services (Non-Slice cost)						
43	Generation Integration	G					
44	Telemetering/Equip Replacement	G					
45	Extra-regional Transmission Acquisitions						
46	**Transmission Acquisition and Ancillary Services Sub-Total**						
47							
48	**Power Non-Generation Operations:**						
49	**PS System Operations**						
50	Efficiencies Program	G					
51	Information Technology	G					
52	Generation Project Coordination	G					
53	Slice Implementation (Slice cost)						
54	**PS Scheduling**						
55	Operations Scheduling	G					
56	Operations Planning	G					
57	**PS Marketing and Business Support**						
58	Sales & Support	G					
59	Public Communication &Tribal Liaison	G					
60	Strategy, Finance & Risk Mgmt	G					
61	Executive and Administrative Services	G					
62	Conservation Support (EE staff costs)	C					
63	**Power Non-Generation Operations Sub-Total**						
64							
65	**Fish and Wildlife/USF&W/Planning Council:**						
66	BPA Fish and Wildlife (includes F&W Shared Services)	F					
67	USF&W Lower Snake Hatcheries	F					
68	Planning Council	G					
69	Environmental Requirements	G					
70	**Fish and Wildlife/ USF&W/Planning Council/Env. Reqt. Sub-Total**						
71							
72	**General & Administrative/Shared Services**						
73	CSRS/FERS Post-Retirement Contribution	G					
74	Agency Services G&A (excludes Direct Project Support)	G					
75	Corporate Support – Shared Services (excludes Direct Project Support)	G					
76	TBL Supply Chain – Shared Services	G					
77	**General and Administrative/Shared Services Sub-Total**						
78							
79	**Bad Debt Expense**	G					
80	**Other Income, Expenses, Adjustments**	G					
81							

	COSTS AND RATE ADJUSTMENTS	Key	Year 1 Forecast	Audited Actual Data	Year 2 Forecast	Audited Actual Data	Total Rate Period
82	**Non-Federal Debt Service**						
83	**Operating Generation Debt Service**						
84	Columbia Generating Station Debt Service	F					
85	Cowlitz Falls Debt Service	F					
86	Northern Wasco Debt Service	F					
87	**Non-Operating Generation Debt Service**						
88	WNP-1 Debt Service	F					
89	WNP-3 Debt Service	F					
90	Trojan Debt Service	F					
91	Conservation Debt Service	F					
92	ENW Retired Debt	F					
93	ENW LIBOR Interest Rate Swap	F					
94	**Non-Federal Debt Service Sub-Total**						
95							
96	**Other Expenses:**						
97	Depreciation	G					
98	Amortization	F					
99	Amortization	C					
100	Interest Expense						
101	Appropriated Interest	G					
102	Capitalization Adjustment	G					
103	Gross Bonds Interest Expense	G					
104	Amortization of Cap Bond Premium	G					
105	AFUDC	G					
106	Interest Earned on BPA Fund for Power						
107	**Interest Expense Sub-Total**						
108	**Total Expenses**						
109							
110	**Revenue Credits:**						
111	Firm Surplus Credit (Excess HWM)	F					
112	Hungry Horse Reservation Credit	F					
113	WNP-3 Revenue Credit	G					
114	Other revenues from BPA contract obligations						
115	RSS revenues						
116	Ancillary Products Revenue	F					
117	4(h)(10)(C) credit	F					
118	Colville and Spokane Settlements	F					
119	Downstream Benefits and Pumping Power	F					
120	Energy Efficiency Revenues	G					
121	Miscellaneous Revenues						
122	Green Tag Revenue	G					
123	Tier 2 Overhead Credit	F					
124	Tier 2 Risk Adder	F					
125	**Total Revenue Credits**						
126							
127	**Minimum Required Net Revenue Calculation:**						
128	Principal Payment of Federal Debt for Power	G					
129	Irrigation Assistance	G					
130	Depreciation	G					
131	Amortization	G					
132	Capitalization Adjustment	G					
133	Bond Premium Amortization	G					
134							

	COSTS AND RATE ADJUSTMENTS	Key	Year 1 Forecast	Audited Actual Data	Year 2 Forecast	Audited Actual Data	Total Rate Period
135	Principal Payment of Federal Debt exceeding Non Cash Expenses	G					
136	**Minimum Required Net Revenues Sub-Total**						
137							
138	**Rate Design Adjustments:**						
139	Low Density Discount	--					
140	Irrigation Rate Mitigation Costs	--					
141	FPS (Surplus)/Shortfall	--					
142	7(c)(2) Delta Allocation (not subject to True-Up)	--					
143	7(b)(3) Protection Amount Allocation (not subject to True-Up)	--					
144	7(b)(2) Industrial Adjustment (not subject to True-Up)	--					
145	Conservation Rate Credit	--					
146	**Rate Design Adjustments Sub-Total**						
147	**Total Composite Cost**						
148							
149	**SLICE COST:**						
150	Slice Implementation Expenses (100 percent allocated to Slice customers)	G					
151	**Total Slice Cost for 100 percent allocated expense)**						
152	**Total Slice Cost for allocation according to Slice percentage**						
153							
154	**NON-SLICE COST:**						
155	Other Power Purchases (Balancing)	F					
156	Other Power Purchases (Capacity)	F					
157	Hedging/Mitigation	F					
158	Third Party Trans & Ancillary Services	G					
159	Interest Earned on BPA Fund	G					
160	Planned Net Revenues for Risk	G					
161	Accrual revenues (MRNR adjustment, if applicable)						
162		--					
163	minus Revenue Credits						
164	Reserve Services	G					
165	Secondary Revenue	F					
166	Demand Revenue	--					
167	Load Shaping Revenue	--					
168	Load Following Revenue	--					
169		--					
170	**Total Non-Slice Cost**						
171							
172	**TIER 2 COST (calculated for each T2 rate):**						
173	Acquisition Costs	F					
174	BPA Overhead Costs	F					
175	RSS Adder	F					
176							
177	**Total Tier 2 Cost**						
180							

	COSTS AND RATE ADJUSTMENTS	Key	Year 1 Forecast	Audited Actual Data	Year 2 Forecast	Audited Actual Data	Total Rate Period
181	**Customer Charge Rate Calculations**		**Composite**	**Slice**	**Non-Slice**		
182	Annual Revenue Requirement (2-year total)						
183	Monthly Revenue Requirement (2-year total divided by 24 months)						
184	Sum of Billing Determinants		100.0	22.6	77.4		
185	One Percent of Monthly Requirement (Rate Per Percent = Monthly Revenue Requirement divided by 100)						
186							
187	Sum of FBS Costs	F					
188	Sum of Exchange Costs	X					
189	Sum of New Resource Costs	N					
190	Sum of Conservation Costs	C					
191	Sum of 7(g) Costs	G					

Cost Allocation Key:

F Federal Base System
X Exchange Resources
N New Resources
C Conservation
G 7(g) Costs

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Figure 2.1

Timeline for HWM, Contract, and Relevant Rate Determinations

(Placeholder)

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Figure 2.2

Contract HWM Determination Process

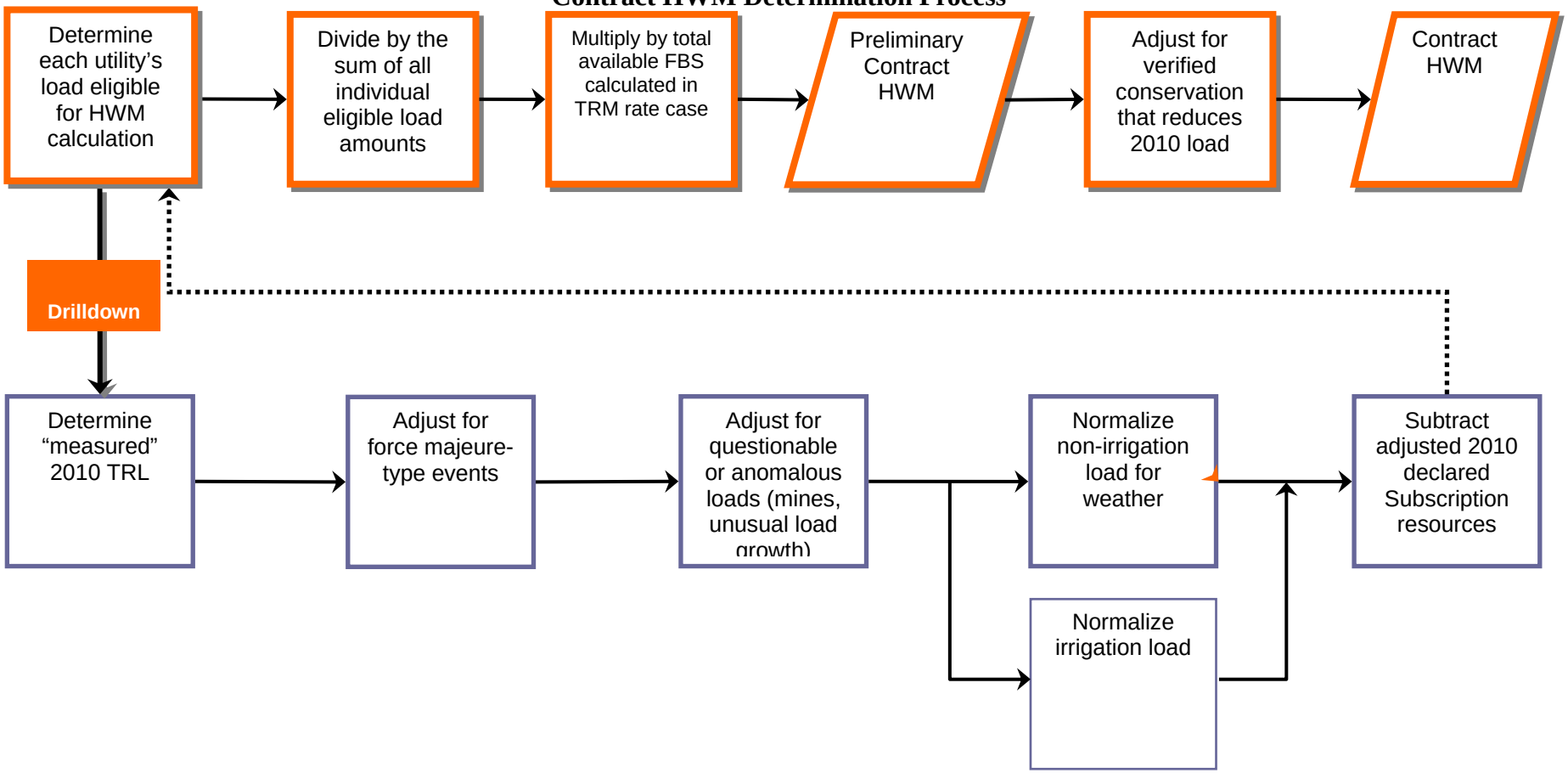

Figure 2.3

Adjustments for Anomalous Loads

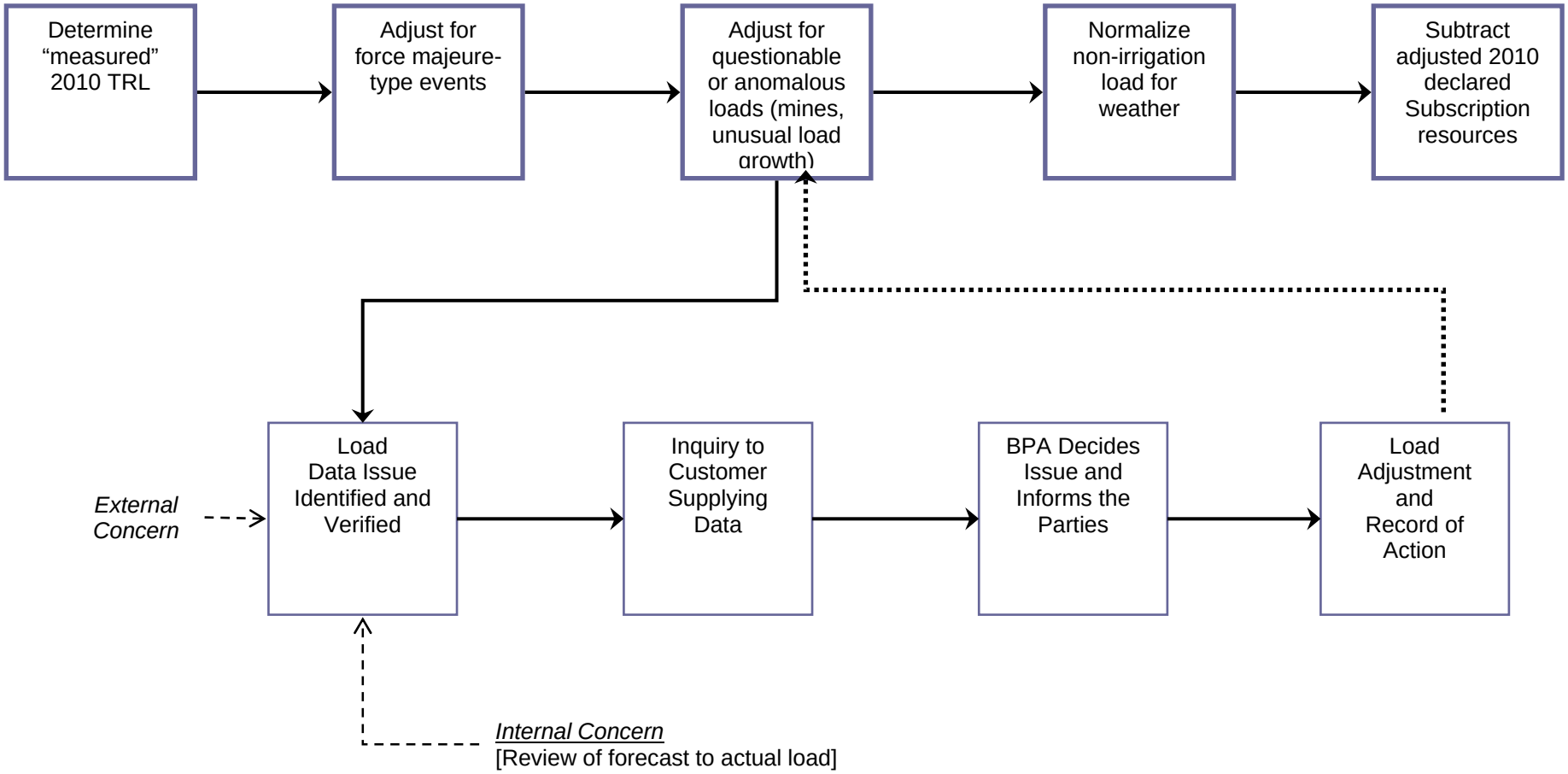

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Figure 2.4a

Non-Irrigation Load Weather Normalization

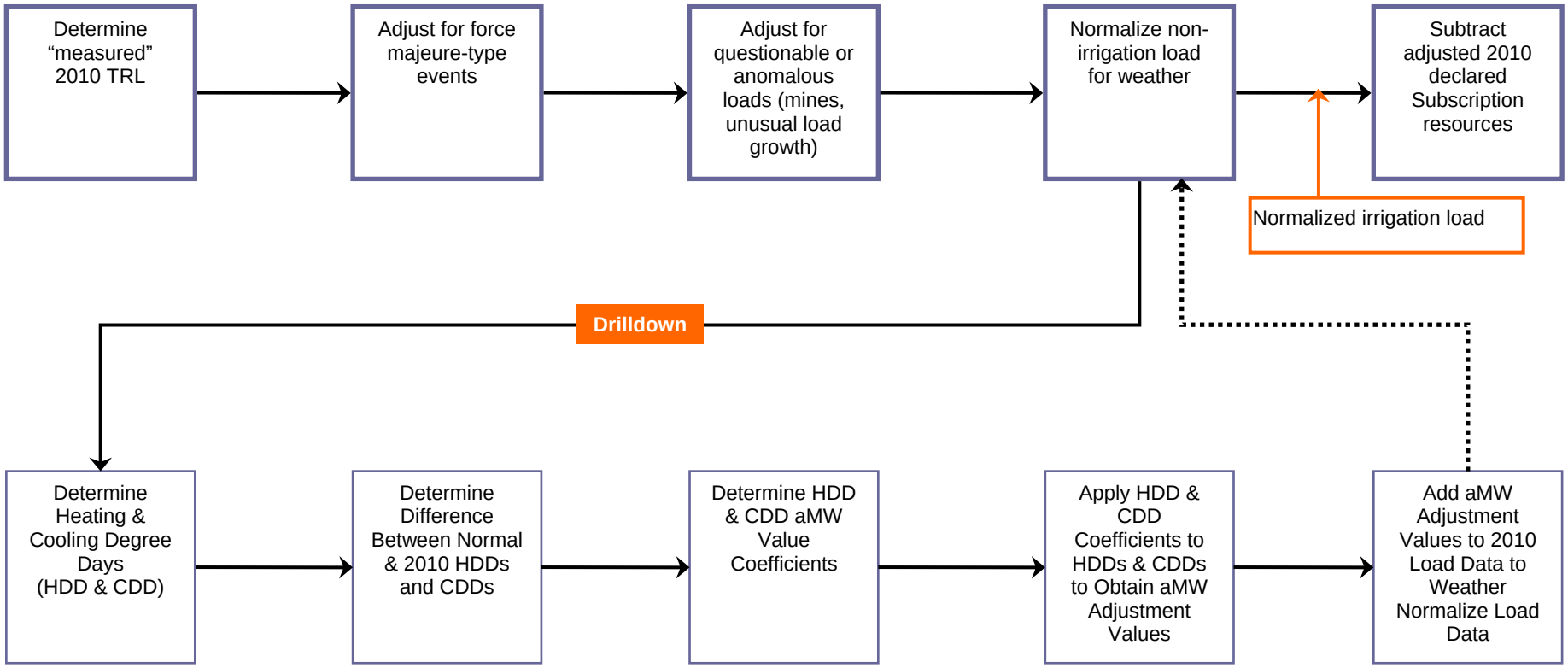

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Figure 2.4b

Irrigation Load Normalization

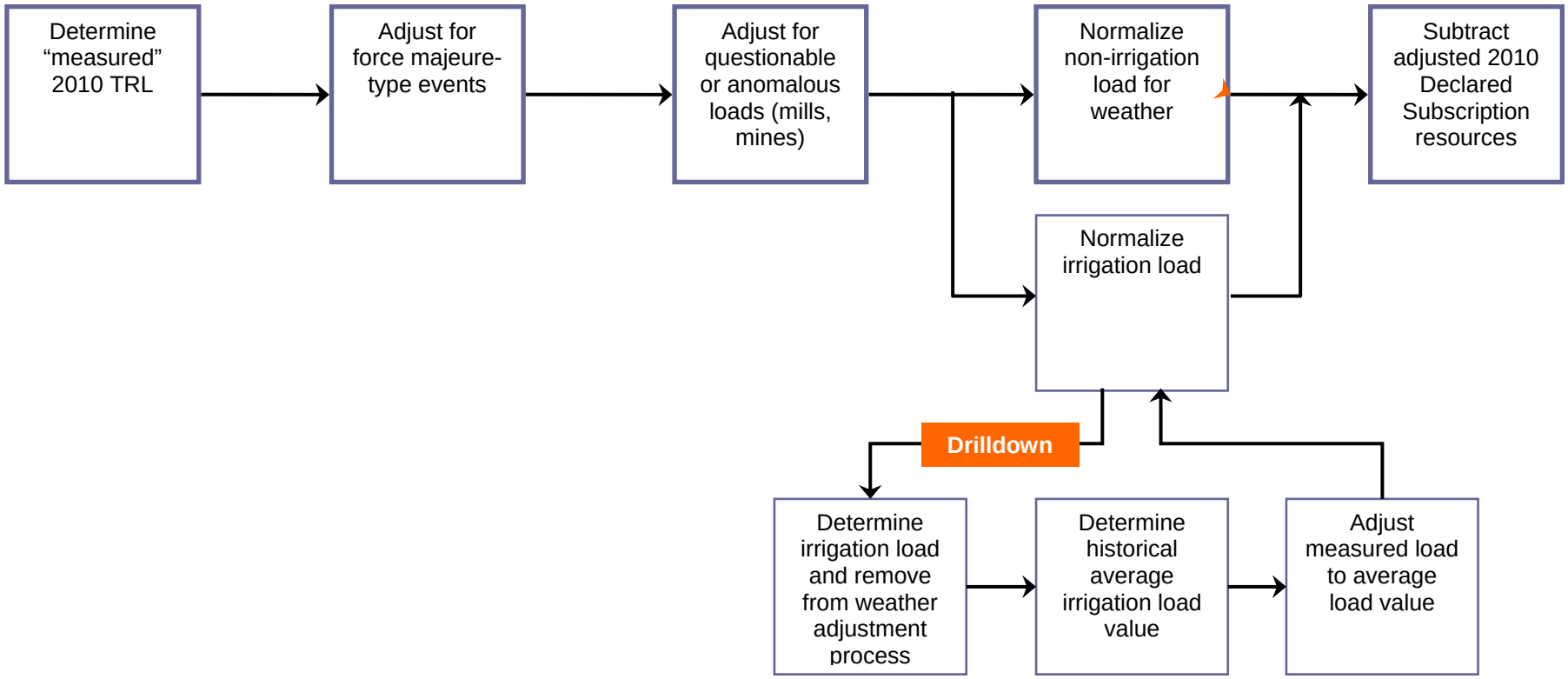

Figure 2.5

Formation of New Publics – Phasing in of HWM Amounts

This example is for a new 64 aMW utility, assuming that additional requests are not received in the future periods that would require amounts beyond the first period to be phased out further in time.

	1st Period	2nd Period	3rd Period	4th Period	5th Period
Initial Amount	10 aMW				
33.3% for next 24	8 aMW	8 aMW	8 aMW		
20% for all else	6 aMW	6 aMW	6 aMW	6 aMW	6 aMW
Annual HWM Addition	24 aMW	14 aMW	14 aMW	6 aMW	6 aMW
Cumulative HWM	24 aMW	38 aMW	52 aMW	58 aMW	64 aMW

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Attachment A

(Placeholder - Product Summaries)

Attachment B

(Placeholder - Determinations of Aggregate 2010 Non-Federal Resource Amounts)

Attachment C

CHWM Calculations and Formulae

1. Customer load eligible for the CHWM calculation is determined.

$$EligibleLoad = 2010ActualLoad_{adjusted} - 2010Resources_{2006defined}$$

where:

$$2010ActualLoad_{adjusted} = 2010ActualLoad \pm 2010WeatherAdj \pm 2010AnomolyAdj$$

$2010ActualLoad$ = the measured firm retail load during FY 2010, with adjustments for (1) load and data anomalies and (2) weather normalization, as described in section 2.1.3:

$2010Resources_{2006defined}$ = Existing Resources

2. FBS augmentation requirements are determined. If the sum of all utilities' eligible load is greater than the planned available 2012 FBS capability,[1] the FBS will be augmented to meet the load amount subject to the limits described in section 3.2.

[1] For the CHWM determination process, the "planned available 2012 FBS capability" will be calculated as the average of the 2012 and 2013 planned available FBS capability, due to substantial differences in CGS capability in alternating years. FBS forecasts for the RHWM determination will be calculated similarly for subsequent rate periods.

3. Eligible load is scaled to the available FBS resource pool, as augmented, to get the preliminary CHWM:

$$CHWM_{prelim} = \frac{EligibleLoad}{\sum EligibleLoad} \times T1SR_{2012}$$

where $T1SR$ = Tier 1 System Resources

4. $CHWM_{(prelim)}$ is adjusted for credited 2007-2010 conservation and rescaled to the FBS resource pool, as described in section 2.1.6, to obtain the final CHWM:

$$CHWM_{final} = \frac{ConsAdjCHWM}{\sum ConsAdjCHWM} \times T1SR_{2012}$$

Attachment D

Conservation Adjustment

Example of Conservation Adjustment Calculation

In Attachment D is a simplified example of how the conservation adjustment works. The example shows a single utility doing varying amounts of conservation. Credit for this conservation is given in row A[2]. In row B, the amount of conservation that was achieved is accounted for in the preliminary HWM (Load with no conservation (100) minus the conservation achieved). In row C, the conservation credit is added back to arrive at the conservation adjusted HWM (row A + row B). In row D, the rebalancing factor is calculated by taking the individual conservation-adjusted HWM (row C) and dividing it by the sum of the conservation-adjusted HWMs for all utilities (row C ÷ 7,470 aMW). In this example the sum of the conservation-adjusted HWMs is 7,470 aMW (the sum of all the utilities preliminary HWM plus the total conservation by all utilities). To establish the Contact HWM the rebalancing factor is multiplied by the available Federal Tier 1 system (row D × 7,300 aMW). As noted in the footnote, as the amount of conservation achieved increases, the amount of augmentation decreases, assuming that the augmentation cap of 300 aMW has not been reached.

[2] In this example it is assumed that all conservation is utility self-funded and 100% credit is given for achieved conservation.

Single Utility Conservation Adjustment Scenarios

Assumptions:
Available FBS = 7300 aMW, incl. 100 aMW aug.
Total Conservation by All Other Utilities = 170 aMW

	Scenario A	Scenario B	Scenario C
Base Case - load with no conservation (FY 2010)	100	100	100
A. Conservation Credit FY 2007 - 2010 (aMW)	0	1	3
B. Preliminary HWM (with effect of conservation)	100	99	97
C. Conservation Adjusted HWM (aMW)	100	100	100
D. Rebalancing Factor = Cons-Adj HWM / Σ Cons-Adj HWMs	100/7470	100/7470*	100/7470*
E. Contract HWM (aMW) (Rebalancing factor X FBS)	**97.72**	**97.72**	**97.72**
Net Change due to conservation adjustment	-2.28	-1.28	.72
Headroom before need to purchase Tier 2 power	0	0	.72

*The increase in the sum of the cons-adj HWMs would be offset by an equal reduction in needed augmentation ➔ no change to 7470 amount

Counting the Conservation Credit toward the Adjustment

The figure below shows how the process of counting conservation savings for the conservation adjustment will take place. The process for verifying savings is described in BPA's Conservation Rate Credit and Conservation Acquisition Agreement Implementation Manual[3] (Implementation Manual). The Implementation Manual must be followed for BPA-funded as well as utility self-funded conservation measures, projects and programs.

[3] All references to the *Implementation Manual* in this section refer to the manual current at the time the project/report is submitted to Planning, Tracking and Reporting system. A copy of this manual can be found on BPA's Web site at http://www.bpa.gov/energy/n/projects/post2006conservation/manual/.

BPA will conduct oversight of all utilities' conservation savings that have been submitted in biannual and annual reports through the Planning, Tracking and Reporting (PTR) system.
To count toward the conservation adjustment, conservation measures and projects eligible for reimbursement according to the Implementation Manual must be started after October 1, 2006 and completed no later than September 30, 2010. Measures must also be effective on load in FY 2010 (*i.e.*, measures where the measure life does not extend through FY 2010 or a major plant closing where measures were implemented, will not count toward the conservation adjustment as they are not reducing FY 2010 load).

Cost-Effective Measures

All savings that are claimed for credit toward the conservation adjustment must be considered cost-effective in accordance with the then-effective Implementation Manual when the conservation is reported to BPA. BPA acquires cost-effective conservation as defined by the Council's Power Plan. In determining cost-effectiveness, the Council looks to section 3(4) of the Northwest Power Act.

Deemed measures in the PTR for which BPA provides a reimbursement are considered cost-effective. Deemed measures are those measures with a predetermined amount of savings.

Custom projects are considered measures or projects for which BPA has not deemed a reimbursement level or for which cost effectiveness has not been pre-determined. These projects must be submitted as Custom Project Proposals (CPPs) and meet all of the Custom Project

requirements, outlined in the Implementation Manual. Refer to the Implementation Manual for more details.

Savings Entry into the Planning Tracking and Reporting System

For savings to be counted toward the conservation adjustment they must be entered into and reported through the PTR annually per the schedule required in the then current BPA Implementation Manual. Annual reports in the PTR for FY 2010 must be submitted in suitable form no later than October 31, 2010. Credit will not be given toward the conservation adjustment for any savings contained in reports which are not submitted on time.

Deemed measures must be reported through the PTR and accepted by BPA's Contracting Officer's Technical Representative (COTR). The acceptance phase is when reports have been reviewed by the COTR and a determination has been sent by BPA accepting the report. Through the oversight process the amount of savings may change either by: 1) a utility notifying BPA that they made an error, or 2) BPA making an adjustment as a result of findings from an oversight review.

For custom projects the Completion Report must be submitted and accepted no later than September 30, 2010, and be included in the Conservation Rate Credit (CRC) FY2010 annual report and/or CAA invoice. All required measurement and verification must take place and be final before the Completion Report is submitted to BPA for acceptance. Oversight applies to custom projects as well.

Transparency of the Annual Conservation Savings Amount

BPA will make public the pre-and post-conservation-adjusted CHWM amounts for each customer, along with the credited conservation amounts used for the adjustment process.

BPA will also release the conservation achievements for each customer on an annual basis for achievements in FY 2007 through FY 2010. This will allow all customers to see the amount of conservation being achieved by other utilities and entities. The release will include BPA-funded and utility self-funded numbers. Note that the oversight process takes place throughout the year and the released numbers may be later adjusted to reflect findings from the oversight process.

Verification and Oversight

Verification and oversight will be conducted in a similar manner for both BPA-funded and utility self-funded claimed conservation. BPA or BPA's agent will review and conduct oversight inspections of report records and monitor or review the customer's procedures, records, conduct site visits and verify energy savings methods and results. The number, timing, and extent of such inspections shall be at the discretion of BPA, and will be coordinated with the customer. These reviews and inspections will occur at BPA's expense.

Oversight may result in a change to the energy savings achieved by a utility, either up or down, after the savings in the reports have been accepted. Therefore, depending on the timing of the oversight, the published conservation achievements may be adjusted to account for findings from the oversight process. For FY 2010, the numbers will be finalized by early 2011 and will not be modified past that time.

Non-Standard Cases and Exceptions

While the standard process as defined above will be followed for the vast majority of measures and projects, there are some situations that will require exceptions as described below.

Federal Conservation Projects

Federal projects will not be required to input measure and project savings into the PTR system. These projects will be imported directly into BPA's Energy Efficiency database. These savings are not put into the PTR because the federal entities claiming the savings are not standard utility customers and are not necessarily utilizing CRC or CAA funding. If a utility wishes to claim savings for projects completed in its service territory at federal facilities for which CRC or CAA funds were used they will need to report the savings through the PTR as required by the Implementation Manual.

Irrigation Rate Mitigation Program

The Irrigation Rate Mitigation program provides participants a one-quarter mill credit ($0.00025) for irrigation load to be utilized for cost-effective conservation measures. These savings are not currently reported through the PTR system. At this time, options are still being explored as to how to best verify these saving so that can be given credit toward conservation adjustment.

For savings to be reviewed and credited toward the conservation adjustment measures and/or projects must be reported annually on the timeline required in the Implementation Manual for CRC and CAA funded measures.

Scientific Irrigation Scheduling

Scientific Irrigation Schedule (SIS) is designed as having a three year measure life, so any SIS measure/program initiated prior to FY 2007 will not be eligible for credit toward the conservation adjustment. Savings over the life of the SIS program are measured and collected, however, only those savings realized in FY 2010 will be credited toward the conservation adjustment. Therefore, irrigation savings will be counted from two different irrigation seasons (*i.e.*, October 2009 and June

– September 2010). Utilities must therefore report all conservation savings attributable to SIS in the annual report for FY 2010 or a previous report.

Transformer De-energization

Transformer de-energization is designed as having a three-year measure life. Only those savings actually realized in FY2010 from transformer de-energization will be credited toward the conservation adjustment.

Attachment E

Example of Calculating the Remarketed Tier 2 Proceeds

Assume that in FY 2014 BPA must remarket 1 aMW of a Load Following customer's Renewable Vintage Tier 2-priced power that is priced at $82.25/MWh in the example above . The summer before the fiscal year that BPA had planned to charge this customer for that 1 aMW, BPA will calculate the average market price used for valuing Tier 2 remarketed amounts. Assume the average price for a flat block of power is $60/MWh. Assume that in the rate case BPA has decided a 10% discount off this market price is the appropriate amount to compensate BPA for the costs described above. A sample customer bill is shown below.

POWER BILL

Purchaser: Public Utility #1 Billing Period: October 2013

Invoice Number: Oct14-EXAMPLE Period Ending: October 31, 2013

Issue Date: November 12, 2013

Sched	Service Desc	Amount	Unit	Rate	Revenue
Tier 1	…	…	…	…	…
Sub-Total					…
Tier 2	Flat Block	1*1,000*744	kWh @	0.08225	$61,194
Tier 2	Remarketed Amount	1*1,000*744	kWh @	0.05400	($40,176)
Tier 2	RSC Adjustment	…	kWh@	0.04500	…
Sub-Total					$21,018
Total					…

Attachment F

Renewable Vintage Tier 2 Rate Example

Assume for purposes of this example only, BPA has 20 aMW of Renewable Vintage Tier 2 rate service committed. It has acquired the output of a 70 MW wind farm at a cost of $70/MWh for the forecast generation of 20 aMW. The RSS associated with this resource cost includes diurnal flattening ($7/MWh) and a resource shaping charge or credit ($5/MWh charge in this example) to price it equivalent to an annual flat block of power. The overhead adder is 20 aMW × 8760 hours × $0.25/MWh, or $43,800 (assuming a $0.25MWh adder.)

The costs allocated to this Renewable Vintage Tier 2 cost pool are reflected in the table below:

Cost Component	**Annual Cost**	**$/MWh**
Resource Cost	12,264,000	70.00
DFS	1,226,400	7.00
Resource Shaping	876,000	5.00
Overhead Cost Adder	43,800	0.25
Total	14,410,200	
Vintage Renewable Tier 2 Rate: (illustrative)		82.25

An individual customer that has subscribed to 3 aMW of power at this Tier 2 rate would be charged $2,161,530 for the year. This amount is before taking into consideration any energy true-ups (through the Resource Shaping Adjustment) or possible remarketing credits/charges discussed below.