

Tiered Rate Methodology Rate Case

Administrator's Record of Decision

November 2008

TRM-12-A-01



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**Tiered Rate Methodology Rate Case
List of Party Abbreviations**

AT	Affiliated Tribes of Northwest Indians Economic Development Corp.
AL	Alcoa, Inc.
AV	Avista Corporation
BC	Benton County Public Utility District
BPA	Bonneville Power Administration
CA	Canby Utility Board
CC	Clark Public Utilities
CK	Clatskanie People’s Utility District
CL	Central Lincoln People’s Utility District
CO	Cowlitz County Public Utility District No. 1
EW	Eugene Water & Electric Board
FR	Franklin Public Utility District
GC	Public Utility District No. 2 of Grant County
GE	Portland General Electric Company
GH	Public Utility District No. 1 of Grays Harbor
GP	Georgia-Pacific, LLC
IN	Industrial Customers of Northwest Utilities (ICNU)
IP	Idaho Power Company
JP	Joint Party of Pacific Northwest Investor-Owned Utilities ¹
LV	Lower Valley Energy
MW	McMinnville Water and Light

¹ Joint Party of Investor-Owned Utilities includes Avista Corporation, Portland General Electric Company, Idaho Power Company, PacifiCorp, and Puget Sound Energy, Inc.

NPJ	Northwest Requirements Utilities and Pacific Northwest Generating Cooperative Joint Party ²
NR	Northwest Requirements Utilities (NRU) ³
PG	Public Generating Pool
PL	PacifiCorp
PN	Pacific Northwest Generating Cooperative (PNGC) ⁴
PO	Public Utility District No. 1 of Pend Oreille County
PP	Public Power Council ⁵

² Northwest Requirements Utilities and Pacific Northwest Generating Cooperative Joint Party includes Northwest Requirements Utilities and Pacific Northwest Generating Cooperative.

³ Northwest Requirements Utilities includes City of Ashland, Benton REA, Big Bend Electric Co-Operative, Inc., City of Bonners Ferry, City of Burley, City of Cascade Locks, Central Lincoln PUD, City of Cheney, Columbia Basin Electric Cooperative, Columbia Power Cooperative, Columbia REA, Columbia River PUD, East End Mutual Electric Co., LTD., Ferry County PUD #1, Flathead Electric Cooperative, City of Forest Grove, Glacier Electric Cooperative, Inc., Harney Electric Cooperative, Hermiston Energy Services, City of Heyburn, Hood River Electric Cooperative, Idaho County Power & Light, Inland Power & Light, Klickitat County PUD, Cootenai Electric Cooperative, Lincoln Electric Cooperative, Inc., Lower Valley Energy, McMinnville Water & Light, Midstate Electric Cooperative, Milton-Freewater City Light & Power, Mission Valley Power, Missoula Electric Coop, Modern Electric Water Company, City of Monmouth, Nespelem Valley Cooperative, Northern Wasco County PUD, Orcas Power & Light, Oregon Trail Electric Cooperative, Peninsula Light, Ravalli County Electric Cooperative, City of Richland, City of Rupert, Salem Electric, Skamania County PUD, South Side Electric, Inc., Surprise Valley Electrification Corp., Tanner Electric Cooperative, Tillamook PUD, United Electric Cooperative, Vera Water & Power, Vigilante Electric Cooperative, Inc., Wasco Electric Cooperative, and Wells Rural Electric.

⁴ Pacific Northwest Generating Cooperative includes Blachly-Lane Electric Cooperative, Central Electric Cooperative, Clearwater Power Company, Consumers Power Inc., Coos-Curry Electric Cooperative, Douglas Electric Cooperative, Fall River Rural Electric Cooperative, Inc., Lane Electric Cooperative, Lost River Electric, Northern Lights Inc., Okanogan County Electric Cooperative, Inc., Raft River Rural Electric Cooperative, Salmon River Electric Cooperative, Inc., Umatilla Electric Cooperative Association, and West Oregon Electric Cooperative, Inc.

⁵ Public Power Council represents the interests of Benton County PUD, Blachly-Lane Electric, City of Ashland, City of Bandon, City of Blaine, City of Bonners Ferry, City of Cascade Locks, City of Cheney, City of Ellensburg, City of Forest Grove, City of Monmouth, City of Port Angeles, City of Richland, City of Rupert Electric Dept., City of Sumas, Clallam PUD, Clark Public Utilities, Clatskanie PUD, Clearwater Power, Columbia River PUD, Columbia Rural Electric, Consumers Power, Cowlitz PUD, Douglas County PUD, Elmhurst Mutual Power & Light, Emerald PUD, Eugene Water and Electric Board, Fall River Rural Electric, Ferry County PUD, Flathead Electric, Franklin County PUD, Grant County PUD, Grays Harbor PUD, Harney Electric, Hood River Electric, Idaho County Light & Power, Idaho Falls Power, Kittitas County PUD, Klickitat County PUD, Lakeview Light & Power Co., Lane Electric, Lewis County PUD, Lincoln Electric, Mason County PUD #1, Mason County PUD #3, McMinnville Water & Light, Milton-Freewater Light & Power, Missoula Electric, Northern Wasco PUD, Okanogan County PUD, Pacific County PUD #2, Parkland Light & Water Co., Pend Oreille PUD, Raft River Electric, Ravalli Electric, Riverside Electric, Salem Electric, Seattle City Light, Skamania County PUD, Snohomish County PUD, Springfield

PPG	Public Power Group Joint Party ⁶
PS	Puget Sound Energy, Inc.
PU	Public Utility Commission of Oregon
RN	Renewable Northwest Project
SC	Slice Customers Joint Party ⁷
SE	City of Seattle
SN	Public Utility District No. 1 of Snohomish County
TI	Tillamook People's Utility District
TU	City of Tacoma
WA	Western Public Agencies Group ⁸
WM	Western Montana Electric Generating & Transmission Cooperative, Inc.

Utility Board, Tacoma Power, Tillamook PUD, Umatilla Electric, Vera Water & Power, Vigilante Electric, Wahkiakum County PUD, Wasco Electric, Whatcom PUD, and Yakama Power.

⁶ Public Power Group includes Cowlitz County Public Utility District No. 1, Northwest Requirements Utilities, Pacific Northwest Generating Cooperative, Public Power Council, Seattle City Light, Public Utility District No. 1 of Snohomish County, Western Public Agencies Group, and City of Tacoma.

⁷ Slice Customers includes Benton County Public Utility District, Clatskanie Public Utility District, Eugene Water and Electric Board, Franklin Public Utility District, Grays Harbor Public Utility District, Pacific Northwest Generating Cooperative, Pend Oreille Public Utility District, Seattle City Light, and Public Utility District No. 1 of Snohomish County.

⁸ Western Public Agencies Group includes Alder Mutual Light Company, Benton Rural Electric Association, City of Port Angeles, City of Ellensburg, City of Milton, Elmhurst Mutual Power & Light Company, Lakeview Power & Light Company, Ohop Mutual Light Company, Parkland Light and Water Company, Peninsula Light Company, PUD No. 1 of Clallum County, PUD No. 1 of Clark County, PUD No. 1 of Grays Harbor County, PUD No. 1 of Kittitas County, PUD No. 1 of Lewis County, PUD No. 1 of Mason County, PUD No. 3 of Mason County, PUD No. 2 of Pacific County, PUD No. 1 of Skamania County, PUD No. 1 of Wahkiakum County, Town of Eatonville, and Town of Steilacoom.

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1.0 Introduction

This Record of Decision (ROD) sets forth the decisions of the Bonneville Power Administration (BPA) Administrator, based on the record compiled in this rate proceeding, with respect to the adoption of a Tiered Rate Methodology (TRM) for Rate Periods from October 1, 2012, through September 30, 2028. The policy context for this section 7(i) proceeding is described below, and includes BPA's Long-Term Regional Dialogue Final Policy and Record of Decision (both released in July 2007) and new power sales contracts that will include Contract High Water Marks (CHWMs), a key feature necessary to implement tiered rates.

This ROD follows an expedited evidentiary hearing, including testimony, briefing, and oral argument before the BPA Administrator. The ROD presents the issues raised by parties in this proceeding, the parties' positions, BPA Staff positions, BPA's evaluations of the positions, and the Administrator's decisions.

1.1 Background

1.1.1 Regional Dialogue Policy

Over the past several years, BPA has engaged the region in discussions known as "Regional Dialogue." The intent of Regional Dialogue has been to define BPA's power supply and marketing role for the long term in a way that meets key regional and national energy goals. Regional Dialogue began in April 2002 when a group of BPA's Pacific Northwest electric utility customers submitted a joint customer proposal to BPA that addressed both near-term and long-term contract and rate issues. Since then, BPA, the Northwest Power and Conservation Council (Council), customers, and other interested parties have discussed and evaluated these near- and long-term issues. Considering the depth and complexity of many of these issues, BPA determined that it would address the issues in two phases. The first phase of Regional Dialogue addressed issues that had to be resolved in order to replace power rates that expired in September 2006. *See* Bonneville Power Administration's Policy for Power Supply Role for Fiscal Years 2007-2011 (February 2005) (Short-Term Policy). The second phase addressed longer-term issues, culminating in BPA's Long-Term Regional Dialogue Final Policy (RD Policy) and Record of Decision (RD Policy ROD), which were published on July 19, 2007.

The timing of Regional Dialogue is critical, because current power sales contracts expire in Fiscal Year (FY) 2011. Utilities need to determine as soon as possible what power they will purchase from BPA at its lowest cost-based rates. More importantly, they need sufficient lead time to make decisions about whether to develop or otherwise secure additional resources, independently from BPA, to serve their load growth in FY 2012 and beyond.

The cornerstone of the RD Policy was set in the Short-Term Policy; there BPA established the policy to limit its sales of firm power at the lowest cost-based rate to public power preference customers to meet their regional firm requirements loads to approximately the firm capability of the existing Federal system. The RD Policy confirmed that policy and directed that the RD Policy be implemented through new power sales contracts, which have been offered to most of BPA's customers, and the TRM, which is being adopted with this ROD.

1.1.2 Collaborative Development Process

In the fall of 2006, BPA Staff began working collaboratively with public power representatives to develop the Tier 1 rate design. *Cherry et al.*, TRM-12-E-BPA-02, at 15. In that informal process, a number of alternatives were considered, ranging from the status quo rate design to rate designs with significant modifications. *Id.* During the ensuing months, the rate design proposed in the TRM began to take shape, using components of a number of different alternatives. *Id.* After about one year, public power representatives coalesced around a general concept that forms the core of the rate design being adopted in the final TRM. *Id.* The collaborative discussions allowed BPA and interested parties to work toward a common understanding of the issues, generate ideas, and when possible propose alternative solutions to specific issues.

This collaboration continued with the release of the Discussion Paper on the Tiered Rates Methodology on December 21, 2007. The Discussion Paper was an early draft of the TRM that was intended to allow interested parties to consider the content and direction of the TRM and to provide comments to BPA Staff in preparation for its initial proposal of the TRM. BPA received 18 comments on the Discussion Paper. These comments significantly furthered BPA Staff's efforts to produce a TRM that would facilitate the implementation of the RD Policy and respond to the concerns of BPA's customers and other stakeholders.

On March 7, 2008, BPA Staff released a Draft TRM that built upon the comments on the Discussion Paper. That Draft TRM was the first comprehensive version of the TRM to be released for further comment by stakeholders. Over the following several weeks, BPA Staff and stakeholders met to discuss the concepts and language in the Draft TRM. The considerable input gained from those meetings led to the Initial Proposal TRM for this proceeding in May 2008.

1.2 Procedural History of This Rate Proceeding

Section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. §839e(i) (Northwest Power Act), requires that BPA's wholesale power rates be established according to specific procedures. These procedures include, among other things, issuance of a notice in the Federal Register announcing the rate proposal; one or more field hearings; the opportunity to submit written views and supporting information; presentation of witnesses; and a decision by the Administrator based on the record. This proceeding is governed by BPA's rules for general rate proceedings contained in the *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg. 7611 (1986) (hereinafter, *Procedures*).

On May 6, 2008, BPA published in the Federal Register its *2012 Tiered Rate Methodology Proceeding; Public Hearings and Opportunities for Public Review and Comment*, 73 Fed. Reg. 24961 (2008). The TRM 7(i) proceeding began with a prehearing conference and the filing of BPA's initial proposal on May 12, 2008. The initial proposal incorporated many of the ideas and solutions arising from the collaborative development process discussed above. BPA Staff's initial proposal consisted of the prefiled written testimony of 19 witnesses and the Initial Proposal Tiered Rate Methodology. At the May 12th prehearing conference, the parties and BPA asked the hearing officer to delay issuing an order establishing a schedule until such

time as BPA and the parties had the opportunity to discuss possible modifications to the proposed schedule. BPA agreed to report back to the Hearing Officer regarding the outcome of the discussions.

In those discussions, all parties expressed a desire to engage in settlement discussions regarding the terms and language of the TRM over the next few months and then resume the 7(i) proceeding under an abbreviated schedule. As part of these settlement discussions, all parties agreed to waive the rule against *ex parte* communications during this period. This waiver was formalized in the Hearing Officer's Order of May 23, 2008. TRM-12-HOO-05. One of the primary reasons parties sought a waiver of the *ex parte* rule was to allow BPA and the preference customers an opportunity to continue to negotiate the power sales contracts that will be subject to rates established pursuant to the TRM. There was a concern that because of the interrelationship between the TRM and the contracts, aspects of contract negotiations could be caught up in *ex parte* rules.

To address concerns expressed by some parties regarding the potential for problems for the 7(i) proceeding created by the *ex parte* waiver, BPA promised all parties that BPA Staff would conduct all TRM settlement discussions in publicly noticed meetings, serve redline versions of the TRM on all parties for review as discussions progressed, and file a supplemental proposal in July 2008 reflecting the results of the discussions. Having BPA Staff file a supplemental proposal would ensure that all parties were afforded the opportunity to comment on any of the proposed changes to the TRM that resulted from the settlement discussions. On May 19, 2008, the Hearing Officer issued an order establishing a modified schedule, setting July 9, 2008, as the second prehearing conference date, at which time the parties would determine the schedule for the remainder of the proceeding. TRM-12-HOO-04.

On July 9, 2008, at the second prehearing conference, BPA filed a motion for order adopting a modified schedule. TRM-12-M-BPA-03. BPA's proposed schedule was discussed and agreed to by the parties during the July 9 prehearing conference, after which the Hearing Officer issued an order establishing a new schedule for the proceeding. TRM-12-HOO-09.

During the settlement period, BPA Staff and parties met over 20 times spanning an 8-week period, came to agreement on a majority of the significant issues, and reached an understanding on many edits to clarify the TRM language. These revisions were reflected in BPA Staff's supplemental proposal, which was filed on July 25, 2008, and consisted of the prefiled written testimony of 13 witnesses and the Supplemental Proposal Tiered Rate Methodology. On August 13, 2008, 15 parties filed direct testimony. The Public Power Group's (PPG's) direct case included a redline version of BPA Staff's Supplemental Proposal Tiered Rate Methodology that reflected edits that parties and BPA Staff had agreed to, and additional edits proposed by the PPG. BPA Staff and the parties filed rebuttal on August 20, 2008. BPA Staff's rebuttal included the Tiered Rate Methodology Redline for BPA Rebuttal Testimony (TRM-12-E-BPA-20). This revised version of the TRM began with the PPG's proposed edits to BPA Staff's Supplemental Proposal TRM. If Staff agreed with the PPG's proposed edits, the edits were left in the document as redlined changes. If Staff disagreed, the edit was rejected, and the rejected edits were reflected in the document. To the extent Staff made new edits, those changes were also identified in the redlined Rebuttal TRM. Cherry, *et al.*, TRM-12-E-BPA-15, at 2. Cross

examination was scheduled for August 25, 2008, but all parties waived cross examination and agreed to enter evidence into the record by stipulation. *See* Order on Admitting Testimony, TRM-12-HOO-16.

BPA and certain parties discussed the possibility of conducting additional settlement discussions to attempt to settle a limited set of outstanding issues. These additional discussions necessitated a further modification to the schedule. BPA filed a motion to amend the schedule (TRM-12-M-BPA-09), which the Hearing Officer subsequently adopted. TRM-12-HOO-20. A settlement conference was held on September 12, 2008, and parties filed briefs on September 18, 2008. Parties' statements of joinder of issues were filed on September 25, 2008. Oral arguments before the Administrator occurred on September 26, 2008. At that time, BPA and parties agreed to convene another settlement conference the following week, on September 30, 2008, to resolve some lingering issues.

As a result of the settlement conferences on September 12 and 30, 2008, BPA filed a motion to supplement the record with proposed modifications to the TRM and to allow for comment on such proposed modifications. TRM-12-M-BPA-11. The modifications to the TRM reflected the changes agreed to between BPA Staff and the rate case parties during those two settlement conferences as well as the degree to which BPA was willing to change the TRM in those instances where BPA and the parties did not reach agreement. The Hearing Officer granted BPA's motion and established October 14, 2008, as the deadline for parties to file motions commenting on BPA's proposed TRM language and identifying portions of their briefs to be withdrawn. TRM-12-HOO-21. The Hearing Officer also allowed for parties to include in their motions any comments regarding the establishment of a new date for issuance of the Record of Decision. *Id.* Five parties filed motions in response to the proposed modifications included in TRM-12-M-BPA-11. After reviewing the parties' comments, BPA established November 10, 2008, for issuance of the ROD.

For interested persons who do not wish to become parties to the formal evidentiary hearings, BPA's *Procedures* provide opportunities to participate in the ratemaking process by submitting oral and written comments. (*See* Section 1010.5 of BPA's *Procedures*.) BPA received nine written comments submitted during the participant comment period, which officially ended August 13, 2008. For discussion of those comments, *see* ROD section 7.0.

This ROD is based on the Administrator's consideration of the entire rate case record.

1.2.1 Waiver of Issues by Failure to Raise in Briefs

While the parties raised many issues in their briefs, there were a number of other issues raised by the parties during the hearing that were not raised in the parties' briefs. Pursuant to Section 1010.13(b) of the *Procedures Governing BPA Rate Hearings*, arguments not raised in parties' briefs are deemed to be waived. Such issues will be implemented based on BPA Staff's stated position in the record.

1.2.2 Settlement of Issues

The nature of this 7(i) proceeding, which developed a methodology but did not set actual rate levels, did not easily lend itself to the traditional 7(i) procedures. In response to parties' requests, BPA and the parties agreed to multiple schedule changes to accommodate off-the-record settlement discussions that could then be moved onto the record, either by BPA or parties, in an agreed-upon manner. As can be ascertained by the procedural history detailed in section 1.2 *supra*, Staff and parties engaged in many discussions that were not part of the formal 7(i) proceeding record. During the May 23 through July 9 period, during which *ex parte* communication prohibitions were waived and Staff and the parties engaged in settlement discussions, notice of such meetings was made to all parties. If Staff and any of the parties engaged in discussions outside of these meetings, such discussions and any resulting proposals were shared and discussed at the noticed meetings. Staff served redlined versions of specific TRM language on all parties for review. Staff also kept a log of TRM-related interactions that occurred between BPA managers (and Staff working on TRM issues) and non-BPA parties. Proposed revisions to the TRM that came about through settlement discussions were made part of the record through Staff's Supplemental Proposal TRM (TRM-12-E-BPA-09), through Staff's redline for rebuttal (TRM-12-E-BPA-20), and through BPA's Motion to Supplement the Record and Allow for Comment (TRM-12-M-BPA-11). These documents allowed parties their due process protections.

1.2.3 TRM Record of Decision as a Final Action

For purposes of subjecting BPA's decisions in this proceeding to judicial review, the issuance of this Record of Decision shall be considered a "final action" under the Northwest Power Act. 16 U.S.C. § 839f(e).

1.3 Legal Guidelines Governing Establishment of Rates

1.3.1 Statutory Guidelines

Section 6 of the Bonneville Project Act of 1937 (Project Act), 16 U.S.C. § 832e, requires that the Administrator prepare schedules of rates and charges for electric energy sold to purchasers. Under the Project Act, rate schedules become effective upon confirmation and approval by the Federal Power Commission, which was succeeded by the Federal Energy Regulatory Commission (FERC or Commission). Section 6 of the Project Act directs the Administrator to establish rates with a view to encouraging the widest possible diversified use of electric energy. Section 7 provides that rate schedules are to be established having regard to the recovery of the cost of producing and transmitting electric energy, including amortization of the capital investment over a reasonable period of years. 16 U.S.C. § 832f.

The Flood Control Act of 1944 (Flood Control Act) contains ratemaking requirements similar to those of the Project Act. Section 5 of the Flood Control Act directs that rate schedules should encourage the most widespread use of power at the lowest possible rates to consumers consistent with sound business principles. 16 U.S.C. § 825s. Section 5 of the Flood Control Act also provides that rate schedules should be drawn having regard to the recovery of the cost of

producing and transmitting electric energy, including the amortization of the Federal investment over a reasonable number of years. *Id.*

The Federal Columbia River Transmission System Act of 1974, 16 U.S.C. § 838 (Transmission System Act), sets forth power ratemaking requirements similar to those of the Flood Control Act and Project Act, plus additional requirements. Section 9 of the Transmission System Act, 16 U.S.C. § 838g, provides that rates shall be established: (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles; (2) with regard to the recovery of the cost of producing and transmitting electric power, including amortization of the capital investment allocated to power over a reasonable period of years; and (3) at levels that produce such additional revenues as may be required to pay, when due, the principal, premiums, discounts, expenses, and interest in connection with bonds issued under the Transmission System Act. Section 10 of the Transmission System Act, 16 U.S.C. § 838h, allows for uniform rates and specifies that the costs of the Federal transmission system be equitably allocated between Federal and non-Federal power utilizing the system.

In addition to the Project Act, the Flood Control Act, and the Transmission System Act, the Northwest Power Act provides numerous rate directives. Section 7(a)(1) of the Northwest Power Act directs the Administrator to establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. 16 U.S.C. § 839e(a)(1). Rates are to be set to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (FCRPS) (including irrigation costs required to be paid by power revenues) over a reasonable period of years. *Id.* Section 7 of the Northwest Power Act also contains rate directives describing how rates for individual customer groups are derived.

1.3.2 The Broad Ratemaking Discretion Vested In the Administrator

The Administrator has broad discretion to interpret and implement statutory standards applicable to ratemaking. These standards focus on cost recovery and do not restrict the Administrator to any particular rate design methodology or theory. *See Pacific Power & Light v. Duncan*, 499 F.Supp. 672 (D.C. Or. 1980); *accord City of Santa Clara v. Andrus*, 572 F.2d 660, 668 (9th Cir. 1978) (“widest possible use” standard is so broad as to permit “the exercise of the widest administrative discretion”); *ElectriCities of North Carolina v. Southeastern Power Admin.*, 774 F.2d 1262, 1266 (4th Cir. 1985).

The United States Court of Appeals for the Ninth Circuit (Ninth Circuit) has also recognized the Administrator’s ratemaking discretion. *Central Lincoln Peoples’ Utility District v. Johnson*, 735 F.2d 1101, 1120-29 (9th Cir. 1984) (“Because BPA helped draft and must administer the Northwest Power Act, we give substantial deference to BPA’s statutory interpretation”); *PacifiCorp v. F.E.R.C.*, 795 F.2d 816, 821 (9th Cir. 1986) (“BPA’s interpretation is entitled to great deference and must be upheld unless it is unreasonable”); *Atlantic Richfield Co. v. Bonneville Power Admin.*, 818 F.2d 701, 705 (9th Cir. 1987) (BPA’s rate determination upheld as a “reasonable decision in light of economic realities”); *Aluminum Company of America v.*

Central Lincoln Peoples' Utility District, 467 U.S. 380, 389 (1984) (“The Administrator’s interpretation of the Regional Act is to be given great weight”); *Department of Water and Power of the City of Los Angeles v. Bonneville Power Admin.*, 759 F.2d 684, 690 (9th Cir. 1985) (“Insofar as agency action is the result of its interpretation of its organic statutes, the agency’s interpretation is to be given great weight”); *Public Power Council v. Bonneville Power Admin.*, 442 F.3d 1204 (9th Cir. 2006).

1.3.3 Confirmation and Approval of Rates

BPA’s rates become effective upon confirmation and approval by the Federal Energy Regulatory Commission. 16 U.S.C. § 839e(a)(2) and (k). The Commission’s review is appellate in nature, based on the record developed by the Administrator. *United States Department of Energy--Bonneville Power Admin.*, 13 FERC ¶ 61,157, 61,339 (1980). The Commission may not modify power rates proposed by the Administrator, but may only confirm, reject, or remand them. *United States Department of Energy--Bonneville Power Admin.*, 23 FERC ¶ 61,378, 61,801 (1983). Pursuant to Section 7(i)(6) of the Northwest Power Act, 16 U.S.C. § 839e(i)(6), the Commission has promulgated rules establishing procedures for the approval of BPA rates. 18 C.F.R. Part 300 (1997).

The Commission reviews BPA rates under the Northwest Power Act to determine whether: (1) rates are sufficient to ensure repayment of the Federal investment in the FCRPS over a reasonable number of years after first meeting BPA’s other costs; and (2) rates are based on BPA’s total system costs. With respect to transmission rates, Commission review includes an additional requirement to ensure that transmission rates equitably allocate the cost of the Federal transmission system between Federal and non-Federal power using the system. 16 U.S.C. § 839e(a)(2). See *United States Department of Energy--Bonneville Power Admin.*, 39 F.E.R.C. ¶ 61,078, 61,206 (1987). The limited Commission review of BPA’s rates permits the Administrator substantial discretion in the design of rates and the allocation of power costs, neither of which are subject to Federal Energy Regulatory Commission jurisdiction. *Central Lincoln Peoples' Utility District v. Johnson*, 735 F. 2d 1101, 1115 (9th Cir. 1984).

The TRM is a rate design methodology that prescribes how BPA will design specific preference customer rates that will go into effect in FY 2012; this methodology will remain in use through FY 2028. The TRM will be applied to establish applicable rates pursuant to section 7 of the Northwest Power Act.

1.4 Issues

Issue 1

Whether BPA should file the TRM with the Federal Energy Regulatory Commission.

Parties' Positions

The PPG, joined by Canby Utility Board, Cowlitz PUD, and Grays Harbor PUD, asserts that it does not believe that BPA has any legal obligation to file the TRM with the Commission until

BPA establishes rates using the TRM. PPG Brief, TRM-12-B-PPG-01, at 29; Canby Joinder, TRM-12-M-CA-01; Cowlitz Joinder, TRM-12-M-CO-01; Grays Harbor Joinder, TRM-12-M-GH-01. The PPG notes that the Commission's role with regard to BPA's rates is to review rates for the limited purpose of ensuring that they are "sufficient to assure repayment of the Federal investment" in the FCRPS and are "based upon the Administrator's total system costs." PPG Brief, TRM-12-B-PPG-01, at 29. The PPG states that because the TRM does not constitute the filing of rates, there is no requirement for the Commission to review it. *Id.*

The PPG states that filing with the Commission will "complicate" ensuring that the TRM and the contracts properly work together. *Id.* at 30. The PPG further notes that BPA should not assume that filing with the Commission provides customers with any added certainty about the provisions of the TRM. *Id.* The PPG states that the contracts or the TRM ROD could be drafted in a fashion to provide customers with the desired certainty that the TRM will not be changed after contracts are signed. *Id.*

BPA Staff's Position

No party specifically addressed this issue during the evidentiary phase of this proceeding; however, section 11 of the TRM specifically contemplates BPA filing the TRM with the Commission.

Evaluation of Positions

The PPG is correct that (1) the Commission's authority to confirm or reject BPA's rates is limited to ensuring cost recovery and that rates are based on BPA's system costs, and (2) that the TRM does not constitute a rate. Nevertheless, the TRM constrains the design of future preference customer rates, so BPA believes that the Commission can provide an important review at this stage of the proceedings. Rather than requesting that the Commission confirm the TRM, BPA instead intends to seek a declaratory order from the Commission to ascertain whether the Commission believes there is any inherent defect with the TRM that would inhibit BPA from recovering its costs. It is important to achieve this understanding now rather than waiting until BPA files rates implementing the TRM for the FY 2012-14 Rate Period. In the event the Commission finds problems with the TRM, such issues are better to know now rather than after the final rate proposal is submitted to the Commission for confirmation and approval.

Decision

BPA will file the TRM with the Federal Energy Regulatory Commission seeking a declaratory order to determine whether the Commission believes any feature of the TRM would inhibit BPA's ability to recover its costs.

Issue 2

Whether BPA should allow additional opportunities to improve the TRM, refraining from finalizing the TRM so as to allow BPA and parties additional time to ensure that the TRM and related contracts work together as intended.

Parties' Positions

The PPG, joined by Canby Utility Board, Cowlitz PUD, and Grays Harbor PUD, proposes that BPA and rate case parties should allow for opportunities to improve the TRM or correct errors or unintended consequences in the TRM until the Regional Dialogue contracts are signed. PPG Brief, TRM-12-B-PPG-01, at 30; Canby Joinder, TRM-12-M-CA-01; Cowlitz Joinder, TRM-12-M-CO-01; Grays Harbor Joinder, TRM-12-M-GH-01. The PPG states that its suggestion would allow these needed changes to be made without having to go through the more rigorous process set out in the TRM. PPG Brief, TRM-12-B-PPG-01, at 30. The PPG proposes that a provision be inserted into the TRM that would allow revisions agreed upon prior to contract signing to be made in the TRM without using the process set out in sections 12 and 13 of the TRM. *Id.* The PPG suggests that such revisions could be reflected in the TRM when BPA files its first set of rates under the TRM. *Id.*

To allow these types of changes to be adopted without resorting to the procedural requirements of sections 12 and 13 of the TRM, the PPG proposes revising section 12 as follows (changes shown underlined):

12. CRITERIA AND CONDITIONS FOR REVISING THE TRM

It will be BPA's policy to revise the TRM as little as possible. BPA reserves the right to revise the TRM, but after the general deadline established by BPA for Publics to sign CHWM Contracts, BPA may revise the TRM only in accordance with the criteria and conditions set forth in this section 12 and the applicable processes set forth in section 13. Reference in this TRM to a "revision" to the TRM means a change in the actual language of the TRM. In this context, revision does not refer to questions of interpretation or implementation of the TRM.

Id.

BPA Staff's Position

Since this issue was raised for the first time in the PPG brief and refined in their comment motion, BPA Staff did not address this issue during the evidentiary phase of the proceeding.

Evaluation of Positions

The PPG proposes to allow BPA and parties to address errors or unintended consequences contained in the TRM and revise the TRM without resorting to the procedural requirements of sections 12 and 13. PPG Brief, TRM-12-B-PPG-01, at 30.

This underlying concept of the PPG proposal has merit. The possibility exists that the TRM may need to be revised to address particular problems that are discovered over the next few months. It makes sense to allow these revisions to happen without resorting to the more rigorous procedural requirements contained in sections 12 and 13. While this proposal is generally sound, the PPG proposal has some procedural shortcomings that need to be addressed.

The PPG proposal would have the proposed changes “collected and formalized, and reflected in the TRM when BPA files its first rates set in accordance with the TRM.” *Id.* It would appear that the PPG proposal would allow these changes to the TRM to be made outside of a 7(i) proceeding. It is important that any changes to the TRM, including those that would fall under the PPG proposal, be formalized through a 7(i) proceeding. Thus, if a provision similar to the one proposed by the PPG is added to the TRM, it should contain some requirement to formalize these changes in a 7(i) proceeding.

The PPG proposal also limits the changes to those agreed to between the issuance of the ROD and the contract signing date, December 1, 2008. The contract signing date may be too early—additional time for BPA and the parties to discuss and agree on these proposed changes would be beneficial. The following revision to TRM section 12 addresses these concerns (*see* underlined words).

12. CRITERIA AND CONDITIONS FOR REVISING THE TRM

It will be BPA’s policy to revise the TRM as little as possible. BPA reserves the right to revise the TRM after February 1, 2009, but only in accordance with the criteria and conditions set forth in this section 12 and the applicable processes set forth in section 13. Any revisions identified before February 1, 2009, must be agreed to by BPA and preference customer representatives designated by the Public Power Council, and will be proposed by BPA after that date in a future section 7(i) rate proceeding, with the revisions not subject to the procedural requirements of sections 12 and 13.

Decision

This ROD establishes the final TRM, which will state that BPA and preference customers may agree on a set of proposed revisions to the TRM prior to February 1, 2009. These agreed-upon changes will be collected and proposed in a future 7(i) rate proceeding to ensure the procedural rights of all rate case parties. Any such agreed-upon changes may be adopted without application of the procedural requirements of sections 12 and 13.

2.0 Tiering of Rates and Contracted For/Committed To Load

Issue 1

Whether the TRM's treatment of "contracted for, or committed to" (CF/CT) load is contrary to the Northwest Power Act.

Parties' Positions

Clatskanie, joined by Eugene Water and Electric Board (EWEB) and Georgia-Pacific (GP), argues that the TRM renders meaningless the treatment of CF/CT load mandated by the Northwest Power Act. Clatskanie Brief, TRM-12-B-CK-01, at 5; EWEB Joinder, TRM-12-M-EW-01; GP Joinder, TRM-12-M-GP-05. Clatskanie contends that the Act's treatment of CF/CT loads is not merely a mandate to serve CF/CT load or an exception to BPA's treatment of a single facility load that exceeds 10 aMW (new large single load (NLSL)), but it is also an obligation to serve that load at a rate that reflects the costs of the Federal Base System (FBS). Clatskanie Brief, TRM-12-B-CK-01, at 6.

GP argues that the proper treatment of CF/CT load under the Northwest Power Act requires that, as the remaining CF/CT amount is utilized by the consumer, such loads must be included in the "general requirements" of the preference customer utility. GP Brief, TRM-12-B-GP-01, at 2. GP argues that because CF/CT load is excluded from the definition of NLSL, BPA's statutory obligation to serve "general requirements" obligations under sections 5(b) and 7(b) applies to the load growth when CF/CT load materializes. *Id.* GP also claims that the Act requires that all general requirements of preference customers be served at the same melded lowest preference rate. *Id.* Therefore, GP concludes that the TRM, in proposing to serve some general requirements of preference customers at the Tier 1 Rate and the remaining general requirements at the higher Tier 2 Rate, is contrary to law and BPA's statutory authority. *Id.*

ICNU, joined by GP, argues that BPA's decision not to provide low-cost power to certain preference customers' CF/CT loads is contrary to the intent and plain language of the Northwest Power Act, inconsistent with sound public policy, and arbitrary and capricious. ICNU Brief, TRM-12-B-IN-01, at 2; GP Joinder, TRM-12-M-GP-05. ICNU supports the TRM as a rate design that is intended to fairly allocate costs among BPA's preference customers while avoiding significant cost shifts among customer groups. ICNU Brief, TRM-12-B-IN-01 at 4. At the same time, ICNU argues that the proposed TRM violates the Northwest Power Act because it eliminates the rate protections of CF/CT loads that increase service after FY 2010. *Id.*

BPA Staff's Position

BPA Staff notes that the TRM provides for BPA general requirements service to the serving utility for CF/CT loads at a Priority Firm Power (PF) rate, consistent with the plain language of the Northwest Power Act, BPA policy, and historical practice. Stene, *et al.*, TRM-12-E-BPA-18, at 3.

Evaluation of Positions

The parties noted above contend that BPA's proposal to tier the PF rate as provided under the TRM will result in power service to future CF/CT load at a higher-cost Tier 2 Rate. These parties argue that charging a Tier 2 Rate for CF/CT load will make such service akin to power that is sold under the New Resources Firm Power (NR) rate for service to NLSLs. GP Brief, TRM-B-GP-01, at 7; ICNU Brief, TRM-12-B-IN-01, at 4; Clatskanie Brief, TRM-12-B-CK-01, at 6.

The parties are mistaken that Federal power supplied to a utility customer to serve its CF/CT load will be sold at what is essentially the NR rate. Although BPA's Tier 2 Rates will be based on marginal cost of newer FBS resources, that does not mean that such rates will be the same as the NR rate, that the utility itself may not meld its costs in its retail rates, or that BPA's tiering of rates is an inappropriate pricing signal for load growth. BPA is not proposing as part of the TRM to establish a different NR rate nor establish an NR rate that would apply to general requirements service. To the contrary, the Tier 2 Rates will be cost-based rates based on FBS resource costs, as defined in the TRM, until such time that the FBS is insufficient to serve general requirements, and the provisions of the TRM are limited to the design and implementation of a tiered PF Preference rate. The TRM does not address issues relating to other BPA rates, such as the NR rate. TRM-12-E-BPA-20 at 2.

Clatskanie, GP, and ICNU argue that CF/CT load should not be treated like an NLSL for purposes of applying BPA's tiered rates. *See, e.g.*, Clatskanie Brief, TRM-12-B-CK-01, at 5; GP Brief, TRM-12-B-GP-01, at 2. That argument mischaracterizes the nature of the TRM treatment of CF/CT load. The TRM's design is grounded on, and is consistent with, the Northwest Power Act, including its treatment of load of a utility that has been determined as "contracted for, or committed to" as still being part of the general requirement load met by the Administrator. 16 U.S.C. § 839a(13)(A). The amount of load that the Administrator determines is CF/CT and that is able to consume electricity is included in the amounts of customer load that BPA serves with general requirements power. *See* 16 U.S.C. § 839e(b)(4). For example, when establishing PF rates, BPA includes in its load forecast CF/CT load that is consuming electricity, along with all other general requirement loads of a customer, except for an NLSL. CF/CT load, whether currently operating or to be realized in the future, will be included in the load that is served as the utility's general requirement, and there is no difference between and among the load that is used for determining the amount of general requirements power BPA sells to its customers under section 5(b) and priced according to section 7(b) of the Northwest Power Act. Therefore, it will not be the case that CF/CT load, in distinction to other load served under general requirements, will be treated like an NLSL.

The TRM, as discussed in greater detail in Issue 2 below, follows closely the language set forth in section 7(b)(1) of the Northwest Power Act. This provision states that the Administrator shall establish "a rate or rates" that are to apply to meet the *general requirements* of BPA's public body, cooperative, and Federal agency customers. Since it uses the plural form "rates," this rate directive clearly permits BPA to establish more than one section 7(b) (PF) rate. 16 U.S.C. § 839e(b)(1). BPA enjoys substantial discretion as to how it designs rates to recover costs appropriately allocated to a rate pool, in this case the PF rate pool. 16 U.S.C. § 839e(e); *City of*

Seattle v. Johnson, 813 F.2d 1364, 1367 (9th Cir. 1987); *Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 1121-22 (9th Cir.1984).

Further, section 7(b) permits BPA to recover the cost (in such rate or rates) of additional power needed to supply sales of power to meet the general requirements of BPA's public body, cooperative, and Federal agency customers that exceed the Federal Base System resources. *Id.* There is no pricing treatment of load that has been determined to be CF/CT that would be contrary to section 7(b)(1), because the TRM is establishing only the method of calculating PF rates that will be of general application to sales of general requirements power made under contracts offered by BPA pursuant to section 5(b). Therefore, these rates that are the byproducts of the TRM are not available or applicable to any NLSLs or other service.

Clatskanie argues that BPA must accord CF/CT load preference and priority to the FBS. Clatskanie Brief, TRM-12-B-CK-01, at 6. Clatskanie misstates the application of preference and priority in this situation. Preference and priority apply in the case of competing applications for Federal power by preference and nonpreference entities to serve load. Only qualified public body and cooperative utilities are accorded preference and priority to power marketed or sold by BPA. *See* 16 U.S.C. § 832c(a) and 16 U.S.C. § 839c(a). *See also City of Santa Clara v. Andrus*, 572 F.2d 660 (9th Cir. 1978) *cert. denied*, 439 U.S. 859 (1978); *Alcoa v. Central Lincoln PUD*, 467 U.S. 380 (1984). The preference clause does not provide a preference to price. *Id.* Preference also does not extend to a specific consumer load that is to be served. Hence, CF/CT loads do not have a preference to service over the other general requirements of BPA preference customers. Load of preference customers is entitled to preference. The TRM does nothing to make the CF/CT loads inferior in preference to service. The TRM is a pricing construct; it does not address preference and priority to service from the FBS. Nowhere does the TRM specify how the FBS will be used, either in serving general requirements or in ratemaking.

Decision

The TRM's treatment of CF/CT load is consistent with preference under section 5 of the Northwest Power Act, treats the CF/CT load as part of the utility's general requirements under section 7, and is not contrary to the Northwest Power Act. The TRM treats CF/CT load in the same manner as all other load of a BPA preference customer that is served with general requirements power that is sold at PF rates.

Issue 2

Whether section 7(b)(1) of the Northwest Power Act requires BPA to meld the costs of resources used to serve the general requirements loads of BPA's preference customers.

Parties' Positions

WPAG, joined by Canby Utility Board and GP, argues that the Northwest Power Act contains express resource cost allocations that must be followed by BPA in constructing the rates charged to preference customers. WPAG Brief, TRM-12-B-WA-01, at 4; Canby Joinder, TRM-12-M-

CA-01; GP Joinder, TRM-12-M-GP-05. WPAG asserts that BPA is required, pursuant to section 7(b)(1), to base the preference customer rate on the costs of the resources in the FBS until preference customer loads exceed the capability of the FBS. WPAG Brief, TRM-12-B-WA-01, at 4. WPAG notes such excess customer loads are then served first by the electric power purchased by BPA under the section 5(c) Residential Exchange Program (REP), and then from other resources acquired by BPA. *Id.* WPAG contends that the statute requires that these resource costs be melded into the preference customer rate. *Id.*

GP contends that the statutory language, the legislative history, and BPA's historical practice support the principle that BPA's section 7(b)(1) rate for power service under section 5(b) must be a single, melded rate applied uniformly to all "general requirements" of preference customers. GP Brief, TRM-12-B-GP-01, at 3, 6. GP contends that section 7(b)(1) does not say that the Administrator can set a separate rate to recover the costs of additional resources for a portion of its general requirements load. *Id.* at 4.

BPA Staff's Position

This issue was raised in rebuttal; however, BPA Staff noted that it was a legal argument properly raised in the parties' briefs.

Evaluation of Positions

WPAG notes that the Northwest Power Act contains express resource cost allocations that BPA must follow in constructing the rates charged to preference customers. WPAG Brief, TRM-12-B-WA-01, at 4. WPAG argues that BPA is required, pursuant to section 7(b)(1), to base the preference customer rate on the costs of the resources in the FBS until preference customer loads exceed the capability of the FBS. *Id.*, citing 16 U.S.C. § 839e(b)(1).

BPA agrees the rate directives of the Northwest Power Act must be followed in constructing the rates charged to preference customers, whether or not such rates are tiered. However, there are several inaccuracies in WPAG's description of the rate directives. First, WPAG stated that section 7(b)(1) requires BPA to base the *preference* customer rate on the costs of resources in the FBS until *preference* customer loads exceed the capability of the FBS. This misstates section 7(b)(1). Section 7(b)(1) says:

The Administrator shall establish a rate or rates of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the Pacific Northwest, *and loads of electric utilities under section 839c(c) of this title.* Such rate or rates shall recover the costs of that portion of the Federal base system resources needed to supply such loads until such sales exceed the Federal base system resources. Thereafter, such rate or rates shall recover the cost of additional electric power as needed to supply such loads, first from the electric power acquired by the Administrator under section 839c(c) of this title and then from other resources.

16 U.S.C. § 839e(b)(1) (emphasis added). Significantly, WPAG leaves out the reference to the loads of utilities participating in the REP pursuant to section 5(c). The issue is not whether preference customer loads alone exceed the capability of the FBS, but rather whether the combined loads of preference customers and 5(c) participants exceed the capability of the FBS. This is an important distinction between WPAG's characterization and the language of the statute. In recent years, the loads of preference customers have been in the range of about 7,000 aMW. The loads of the 5(c) participants are in the range of about 5,000 aMW. The size of the FBS is in the range of about 7,000 aMW. Therefore, the combined loads referred to in section 7(b)(1) are already far in excess of the size of the FBS.

WPAG also argues that the statute requires that these resource costs be melded into the preference customer rate. WPAG Brief, TRM-12-B-WA-01, at 4, *citing* 16 U.S.C. § 839e(b)(1). GP contends that the statutory language supports the principle that BPA's section 7(b)(1) rate for power service under section 5(b) must be a single, melded rate applied uniformly to all "general requirements" of preference customers. GP Brief, TRM-12-B-GP-01, at 3, 6.

BPA disagrees with WPAG's and GP's interpretation of section 7 of the Northwest Power Act. Congress did not mandate in section 7 that BPA establish a specific rate form or require BPA to adhere to any particular method of rate design. On the contrary, the statutory language of the Northwest Power Act, and in particular section 7(e), vests the Administrator with considerable discretion in designing rates. Section 7(a)(1) of the Northwest Power Act sets the overall tone of section 7 by directing the Administrator to "establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity" and "to recover, in accordance with sound business principles, the costs associated with the acquisition ... of electric power including the amortization of the Federal investment in the [FCRPS] ... and the other costs and expenses incurred by the Administrator" 16 U.S.C. § 839e(a)(1). The key to section 7 is that BPA must establish rates in accordance with BPA's statutory authorities and sound business principles to recover total system costs. *Id.* at § 839e(a)(2).

In section 7(b), Congress addressed the establishment of rates for preference customers and Federal agencies, and customers participating in the Residential Exchange Program. Section 7(b)(1) directs BPA to establish "a rate or rates of general application" for the sale of power to such customers that recover costs associated with the resources used to supply such power. Section 7(b)(1) provides:

The Administrator shall establish a *rate or rates* of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the Pacific Northwest... . Such *rate or rates* shall recover the costs of that portion of the Federal base system resources needed to supply such loads until such sales exceed the Federal base system resources. Thereafter, such *rate or rates* shall recover the cost of additional electric power as needed to supply such loads, first from the electric power acquired by the Administrator under section 839c(c) of this title and then from other resources.

16 U.S.C. § 839e(b)(1) (emphasis added). In this provision, Congress identified, with specificity, two cost recovery goals associated with the establishment of preference customers'

rates. First, BPA’s “rate or rates” for preference customers must first recover the costs of that portion of FBS resources that are necessary to serve such loads, and second, such “rate or rates” must recover the costs of any additional resources, beyond FBS resources, that are necessary to supply such loads. Congress clearly envisioned the possibility of more than one PF rate. *See also* 16 U.S.C. § 839e(c)(2) (“applicable wholesale rates to such public body and cooperative customers”). This, in fact, has been BPA’s practice, with irrigation rates and the Slice rate being examples of variant rate design forms.

Section 7(e) is a savings clause of sorts and states in clear language that nothing in the Northwest Power Act prohibits the Administrator from using any particular rate form or design to establish rates.

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

16 U.S.C. § 839e(e) (emphasis added). Congress expressly authorized BPA to establish “a rate or rates” for the sale of power to meet preference customers’ loads and did not dictate any particular rate form. On the contrary, Congress included section 7(e) for the purposes of clarifying that BPA has broad rate design discretion under the Act. The legislative history of section 7(e) expresses Congress’s recognition that the rate directives expressed in the Northwest Power Act govern the amount of revenue BPA’s rates should be designed to collect, rather than the form or design of the rate itself. H.R. Rep. No. 96-976, Part I, 96th Cong. 2d Sess., 69 (1980). As such, the clear and unequivocal language of sections 7(a), 7(b)(1), and 7(e) provides BPA legal authority to establish the proposed TRM. These provisions demonstrate that Congress anticipated BPA’s need for flexibility in rate design and recognized that it would be impractical to codify or impose upon BPA by statute any specific rate form. The proposed TRM establishes, consistent with BPA’s statutory authorities, the rate design that BPA will use to recover the costs BPA incurs to supply general requirement loads of preference customers.

Nevertheless, despite the clarity of this statutory language, GP argues that section 7(e) does not provide BPA with the necessary authority to adopt tiered rates. In support of this argument, GP relies on an excerpt from legislative history (Appendix B to the Senate Report) to suggest that Congress did not “overturn the historical practice of uniform rates for service to all general requirements.” GP Brief, TRM-12-B-GP-01, at 8. However, GP’s argument is a *non-sequitur*: the fact that Congress stated in a brief passage of legislative history that it would not, in effect, preclude BPA from establishing uniform rates for service to all general requirements does not mean Congress required BPA to do so. On the contrary, the cited passage demonstrates that, consistent with section 7(e), Congress was not willing to impose any particular rate form or rate design on BPA and recognized that BPA could establish uniform rates as well as other rate forms.

WPAG contends that the TRM does not contain an explanation of how its resource cost segregation and allocation can be reconciled with the rate directives in sections 7(b)(1) and (2) of the Northwest Power Act, which compel different resource cost allocations, resource cost melding, and rate ceilings. WPAG Brief, TRM-12-B-WA-01, at 6.

Contrary to WPAG's contention, the TRM is predicated on the expectation that the costs of resources included in the tiered rates for preference customers will be consistent with the costs of the resources allocated to the loads of customers under section 7(b)(1). BPA remains free to designate as FBS resources those resources necessary to provide power priced at the Tier 2 Rates.

BPA has explained that it is establishing the tiered rate design to differentiate between the costs of service associated with Tier 1 System Capability for existing preference customer load and the costs associated with amounts of power needed to serve any portion of a Public's Annual Net Requirement not served at a Tier 1 Rate. TRM-12-E-BPA-20 at 1. If necessary to satisfy the requirements of section 7(b), resources acquired to serve preference customer general requirements can be made part of the FBS.

This rate design comports with the section 7(b)(1) directive that BPA is authorized to establish a rate or rates that will recover in total the cost of additional electric power as needed to supply loads that exceed the FBS resources. 16 U.S.C. § 839e(b)(1). The term Tier 1 System Capability is based on Tier 1 System Resources, which by definition and operation under the TRM are a portion of the FBS as it is planned in FY 2012. Accordingly, any costs associated with amounts of power needed to supply general requirements loads not met by the Tier 1 System Resources will be recovered under the Tier 2 Rates. In total, all costs of both portions of the FBS will be recovered under the tiered PF rate, even though the PF rate is bifurcated. This proposal is fully consistent with the language of section 7(b)(1) providing that rates for preference customers will recover, first, "the costs of that portion of the Federal base system resources needed to supply such loads..." and second, the "cost of additional electric power as needed to supply such loads." 16 U.S.C. § 839e(b)(1).

Section 7(b)(2) states that "the projected amounts to be charged for firm power for the combined general requirements ... may not exceed in total ... an amount equal to the power costs for general requirements of such customers if, the Administrator [makes certain assumptions]..." 16 U.S.C. § 839e(b)(2). Staff has acknowledged that there are implementation issues related to how BPA will conduct the section 7(b)(2) rate test under the TRM in the future that still need to be worked out. *Cherry, et al.*, TRM-12-E-BPA-15, at 14. However, there is nothing in the TRM that presents a conflict with section 7(b)(2), that changes or in any way directs how section 7(b)(2) will be applied in ratesetting under the TRM, or that will deny preference customers any of the rate protection that may be due to them resulting from the application of section 7(b)(2).

WPAG states that "BPA may suggest that all it proposes to do in the TRM is merely a rate design exercise authorized under section 7(e) of the Northwest Power Act." *Id.*, citing 16 U.S.C. § 838e(e). WPAG continues that this section of the Northwest Power Act gives BPA authority to adopt "other rate forms." WPAG Brief, TRM-12-B-WA-01, at 5. WPAG states that such an argument would likely be unavailing on appeal. *Id.*

BPA does rely on section 7(e) as one source of authorization for tiering rates. *See also* section 1.3 of this ROD. But, contrary to WPAG's assertions, the TRM neither renders portions

of section 7 as surplusage nor overrides substantive protections afforded to preference customers in the Northwest Power Act. Despite WPAG's attempts to associate the TRM to the court-voided 2000 Residential Exchange Settlement Agreements, *id.* at 6, the TRM is much different. Whereas the residential exchange settlements were an attempt to settle the REP as a replacement for the statutorily mandated section 5(c) exchange, tiered rates are not a replacement of a statutorily required cost allocation exercise. Rather, the TRM institutes a rate design for preference customers based on the costs allocated to preference customers after application of the cost allocations pursuant to sections 7(b)(1), 7(b)(2), and 7(g). There is nothing in the TRM that in any way compromises or circumvents or modifies the rate directives of section 7, and despite claims to the contrary, WPAG has shown no specifics as to how such a rate design conflicts with section 7.

Finally, WPAG states that it can only be concluded that the question of whether rates designed in accordance with the TRM are contrary to law will be determined when such rates are finally set in the appropriate 7(i) Process and reviewed by the Ninth Circuit. *Id.*

The intent of the TRM is to implement tiered rates in a manner entirely consistent with, and subservient to, the section 7 rate directives. BPA does not currently see any provision in the TRM that is in conflict with the section 7 rate directives. If, during the implementation of the TRM, a provision of the TRM is found to be in conflict with the section 7 rate directives, BPA will work with parties to the TRM rate case to resolve such conflict and revise the TRM under the unintended consequences provisions of the TRM. Alternatively, sections 12 and 13 of the TRM preserve BPA's full authority to modify the TRM to respond to court order.

GP contends that section 7(f) allows BPA to construct other rate forms, but that section 7(b) does not. GP Brief, TRM-12-B-GP-01, at 4. GP added that section 7(j) of the Northwest Power Act requires BPA to publish the cost of the additional resources "procured" to augment the FBS, and argues that if Congress had intended to allow BPA to create a separate, marginal rate to reflect such additional costs, Congress would not have required separate, specific publication of such costs. *Id.* GP claims that BPA's reading of the statute would render section 7(j) superfluous and meaningless. *Id.*

BPA disagrees with GP's interpretation of sections 7(f) and 7(j). Section 7(f) applies only to "[r]ates for all *other* firm power sold by the Administrator . . ." 16 U.S.C. § 839e(f) (emphasis added). Therefore, it does not apply to the establishment of the PF rate pursuant to section 7(b) and hence does not stand for the proposition, as argued by GP, that section 7(b) does not refer to or allow rates differentiated based on the subset of resources procured. GP Brief, TRM-12-B-GP-01, at 4.

GP's argument with respect to section 7(j) is equally defective. The purpose for section 7(j) is to provide customers information as to the costs of different resource categories and new resources, and it allows customers and their ratepayers to indicate the costs of load growth. That section has no substantive operation or application for the setting of rates by BPA under section 7. Therefore, contrary to GP's argument, the proposed TRM does not make the section 7(j) information requirement superfluous and meaningless; quite the opposite. The TRM serves the purposes of section 7(j) and will be particularly useful in identifying the costs of power that is

acquired to serve customer load beyond that which is served by Tier 1 System Resources. As BPA Staff testified,

The Tier 2 Rate should not be equated with Federal power that would be used to serve only a customer's load growth. Although load growth is expected to be the largest component of above-RHWM load, it would be possible for a customer without load growth to be faced with a situation of purchasing at Tier 2 Rates. The firm critical output of Tier 1 System Resources may decline in the future. Such a decline in output would reduce customers' RHWMs, resulting in increased exposure to Tier 2 rates. In this case, the proposed TRM rate design would allow customers to more clearly see BPA's costs of replacing some or all of the decreased firm critical output of Tier 1 System Resources.

Cherry, *et al.*, TRM-12-E-BPA-02, at 8.

GP contends that BPA must serve general requirements load at a uniform, lowest rate, reflecting a melded rate that takes account of all costs associated with serving the general requirements of preference customers pursuant to the "formula" set forth in section 7(b). GP Brief, TRM-12-B-GP-01, at 9. GP quotes language from a section-by-section analysis related to section 3(13) of the Northwest Power Act, which states that service for NLSLs at the section 7(f) rate would likely be at the marginal cost of power. *Id.* GP argues that this section 7(f) comment suggests that the section 7(b) rate available for all preference customers other than NLSLs is not a marginal cost-based rate. *Id.* GP contends, without citation, that it "was generally understood" during consideration of the Northwest Power Act that BPA would continue its historical practice of using a melded rate for preference service. *Id.* at 9-10. GP notes that proposals by the City of Seattle and Representative Weaver to mandate a form of tiered rates were rejected by the House of Representatives. *Id.* at 10. GP argues that BPA's explanation that its monthly billings will effectively meld the rate is "unreasonable semantic gaming" and that by differentiating and segregating to the Tier 2 Rate costs of one portion of the FBS to serve additional CF/CT load, the utility will treat that portion of its general requirements service to its consumer's CF/CT load inequitably and with undue discrimination. *Id.* at 11.

First, BPA's rates are wholesale power rates and not retail service rates. GP's claim that the TRM will treat CF/CT load inequitably and with undue discrimination is misdirected, because the TRM does not establish retail rate structures. BPA does not directly serve the retail load of its utility customers, including any CF/CT load or NLSL load. Retail ratesetting is the province of the local utility. Congress recognized in the context of large retail loads that BPA's utility customers have the authority to set their retail rates so that whatever the cost of power sold by BPA, "[i]t will remain possible, ... for a public utility to subsidize industry with lower-cost residential power. This would, of course, need the consent of the utility's governing body." H.R. Rep. No. 96-976, Part I, 96th Cong. 2d Sess., 44 (1980).

Second, the price signals that will result from the TRM are intended to inform the local utility of the wholesale power costs incurred by BPA in supplying power needed by the utility to serve its load and how the utility may best structure its resource acquisitions over the next 20 years. These wholesale rates will not impose any limitation on the utility to set its retail rates in a

manner that either subsidizes a consumer's future CF/CT load or equitably allocates costs among all retail consumers that are served by the utility with power bought at the wholesale level as general requirements load. Under the TRM, the Tier 2 Rates are rates of general application, and any Federal power that is supplied to serve a customer's general requirement load, irrespective of it being CF/CT load or other non-CF/CT load, that is above the customer's RHWL will be sold at a Tier 2 Rate.

Therefore, BPA disagrees with GP's claim that the TRM will treat CF/CT load inequitably and with undue discrimination: the cost signals BPA provides its utility customers through BPA's wholesale power rates may not, in turn, be mirrored in the retail rates the local utility applies to retail power sold to any CF/CT load it serves. BPA's utility customers establish their own retail rates and may choose to meld, flatten, or reduce the rates applicable to any segment of their retail loads in any manner they deem reasonable. As such, the retail utility's actions may dampen the effects of the wholesale rate level and design at which they buy from BPA or any other wholesale power supplier.

Third, BPA's statutes do not include a discrimination or undue discrimination standard applicable to BPA's rates for the sale of electric power. Nevertheless, there is nothing discriminatory about the proposed TRM. The TRM will support the establishment of tiered rate schedules that are of general application and are uniform. Specifically, Tier 1 Rates will be applied to all sales of power to customers to meet their load that is below their RHWL, while Tier 2 Rates will be applied to all sales of power to customers to serve the amount of their Above-RHWL Load they choose to purchase from BPA.

Next, GP attempts to infer by its argument, *see* GP Brief, TRM-12-B-GP-01, at 23, that the word "uniform" has the same meaning as the word "melded." It does not, and BPA will not read into the Northwest Power Act an inference of words that are not there. For one thing, "uniform" is a vestige of when BPA's power and transmission rates were combined, and Congress was directing that customers whose loads were distant from the source of Federal generation would pay the same or "uniform" cost for the transmission of Federal power. *See* Bonneville Project Act, section 6, 16 U.S.C. § 832e. However, as applied to rates for the sale of power, the language in section 7(b)(1) contains the words "rate or rates of general application." Section 7(b)(1) does not contain the word "uniform," although that does not preclude each of the "rates" established pursuant to section 7(b)(1) from being uniform. In section 7(e), Congress stated that nothing in section 7 prohibits the Administrator from establishing in rate schedules of general application, "a uniform rate or rates ... or other rate forms." 16 U.S.C. § 839e(e). Uniform in this context means that rate designs or rate forms should be applied to those customers that purchase power from BPA under rate schedules of general application. The TRM, as proposed, is consistent with this direction.

While BPA has historically used a melded rate design, section 7(e) is clear that BPA is not precluded from adopting a different rate design. Tiered rates provide BPA with a rate design that will further the long-term interest of the region as a whole. In the RD Policy, BPA set forth the policy goals and objectives furthered by a tiered rate structure.

Promotion of Regional Electric Infrastructure: Adequate infrastructure development is essential to ensuring a reliable future power supply and to avoiding excessive market price volatility such as occurred during the West Coast energy crisis of 2000-2001. Although the region is not currently short of generation resources, new resource development requires long lead times. While public utilities and resource developers are motivated and able to develop new power resources, they need certainty about how much low-cost power each utility can purchase from BPA in the long term and how BPA will price its power. Defining the amount of power each customer is eligible to purchase from BPA at the lowest-cost Tier 1 rate (the HWM) will allow utilities to move forward with plans to meet their additional or new load by developing their own resources or purchasing additional power from BPA at a potentially higher Tier 2 rate. ...

Low and Stable BPA Tier 1 Power Rates: Low power rates are one of BPA's most important contributions to the regional economy. The Policy will help to keep BPA's Tier 1 rate low and stable by greatly reducing the amount of augmentation cost included as part of a Tier 1 rate. Historically, these augmentation costs have been one of the largest drivers of BPA rate increases.

* * * *

Enhanced BPA Financial Stability and Assurance of Treasury Payments: A low and stable Tier 1 rate created by a major reduction in BPA's past practice of acquiring new power and melding its costs with those of the existing system will greatly reduce the financial uncertainty that occurred when BPA rates rose above wholesale market prices. This rate stability should significantly reduce future risks to BPA's ability to make its Treasury payments. Long-term take-or-pay commitments from customers will add further assurance that BPA will make those payments in full and on time, as will largely relieving BPA of the obligation to acquire power to replace reductions in existing system output at melded rates.

RD Policy at 5-6. GP's argument that BPA is constrained from altering its historical practice of melding the costs of resources when setting rates ignores the fact that a tiered rate structure is not only consistent with BPA's statutory authorities but is in the long-term interest of the region. Fostering resource development, ensuring BPA rates are low and stable, and enhancing BPA's financial stability are all furthered through the transition to tiered rates. Effective and efficient price signals also further the positive environmental goal of ensuring that customers better understand the true cost of their actions. This, in turn, induces customers to conserve power. BPA is not limited from establishing a rate design that promotes the purposes of the Northwest Power Act and serves the important public policy interest identified above.

BPA acknowledges that while the Northwest Power Act was being considered by Congress, discussion occurred about whether BPA should be mandated to implement a two-tier rate structure. At the same time, Congress chose not to include express language in the Northwest Power Act that would have required a particular rate design. The Ninth Circuit explained that, instead, the legislative history "shows only that Congress rejected a 'multi-tier pricing'

amendment that would have *mandated* direct assignment of the cost of new energy sources to certain customer classes.” *Central Lincoln Peoples’ Utility District v. Johnson*, 735 F.2d 1101, 1122 (9th Cir. 1984) (*Central Lincoln II*) (emphasis added), *citing* 126 Cong.Rec. H10, 526-27 (daily ed. Nov. 12, 1980), reprinted in BPA Legislative History at 171-72. Significantly, the Court went on to note that

...*the Act specifically allows the Administrator latitude in choosing rate forms. See 16 U.S.C. § 839e(e). Because a main purpose of the Act is to encourage conservation and efficiency, 16 U.S.C. § 839(1), the Administrator is given discretion to achieve these purposes through rate design. That the Act specifies certain methods of conservation cannot reasonably be read to prohibit other conservation measures. Indeed, the House Interior Committee comments on 16 U.S.C. § 839e(e) specifically state that the statute permits rate forms “designed to give BPA customers price signals,” such as the LRIC. House Report, Part II, supra, at 53.*

Id. (emphasis added).

As noted above, during the drafting of the Northwest Power Act, amendments were offered that would have mandated a tiered rate structure. *See, e.g., Pacific Northwest Electric Power Planning and Conservation Act, 1979: Hearings on S. 885 Before the Senate Comm. on Energy and Natural Resources, 96th Cong. 1st Sess., at 108-109, 121-122 (1979)* (statement of Mr. Randy Revelle, Chairman, Seattle City Council Energy Committee). GP has attempted to infer, from the fact that these amendments were not included in the final Bill, that the Northwest Power Act mandated melded rates and prohibited tiered rates. Specifically, GP quoted a floor statement made by Representative Dingell to support its argument that BPA’s historical practice to meld costs supports the principle that BPA’s rate for service under section 5(b) must be a melded rate applied uniformly to all general requirements of preference customers. GP Brief, TRM-12-B-GP-01, at 5-6. However, the legislative history cited by GP merely notes that there was a wide variety of amendments the House had considered and, for one reason or another, had not adopted. The cited legislative history does not state or imply that the Northwest Power Act prohibits BPA from establishing tiered rates.

Moreover, as a general matter, this legislative history does little to advance GP’s argument. The Ninth Circuit has held that it will not read statutory prohibitions into the Northwest Power Act that constrain the Administrator’s discretion based merely on inference. For instance, with respect to BPA’s Intertie Access Policy, the Court found that, “Congress has never disapproved a policy allocating Intertie access on a pro rata basis despite being aware that BPA contemplated such a policy even before the Intertie was constructed... In outlining this history we do not mean to suggest that Congress has approved the Formula Allocation. This history does indicate, however, that Congress has not prohibited such a policy and that it is within BPA’s discretion to adopt a pro rata allocation scheme.” *California Energy Com’n v. Bonneville Power Administration*, 909 F.2d 1298, 1311, n.12 (9th Cir. 1990). This ruling contradicts GP’s notion that BPA is required to have melded cost rates that apply to sales under section 5(b) of the Northwest Power Act.

In rejecting a mandatory tiered rates structure, Congress did not prohibit such a structure. Lacking clear direction from Congress as to the structure of BPA's rates, it must be concluded that Congress left such determination to the discretion of the Administrator. *See also Central Electric Power Cooperative, Inc., et al., v. Southeastern Power Administration, et al.*, 338 F.3d 333, 337 (4th Cir. 2003), quoting *Town of Norwood v. FERC*, 962 F.2d 20, 22 (D.C.Cir.1992) ("since 'issues of rate design are fairly technical and, insofar as they are not technical, involve policy judgments that lie at the core of the regulatory mission,' [Southeastern Power Administration] enjoys considerable discretion in determining how to structure the recovery of such costs.")

Decision

Section 7(b)(1) of the Northwest Power Act does not require BPA to meld the costs of resources used to serve the general requirements loads of BPA's preference customers. Section 7(b)(1) expressly authorizes the Administrator to establish a rate or rates for power sold pursuant to contracts offered under section 5(b)(1) of the Act. Section 7(e) provides the Administrator substantial discretion to design rates to provide appropriate price signals, while recovering in total from each rate class the amount of money required by the rate directives of the Northwest Power Act. The establishment of tiered PF rates under the proposed TRM is authorized by and consistent with these express statutory directives and authorities.

Issue 3

Whether a customer's unrealized CF/CT load should be included as an adjustment to a customer's CHWM in FY 2010 and thus be guaranteed service at the Tier I Rate.

Parties' Positions

Clatskanie, joined by EWEB and GP, argues that the TRM renders meaningless the treatment of CF/CT load mandated by the Northwest Power Act. Clatskanie Brief, TRM-12-B-CK-01, at 5; EWEB Joinder, TRM-12-M-EW-01; GP Joinder, TRM-12-M-GP-05. Clatskanie claims that BPA must treat any CF/CT load that was planned on September 1, 1979 as if it is actual existing load. Clatskanie Brief, TRM-12-B-CK-01, at 7. Clatskanie also argues that under sections 7(b)(3) and 3(13)(A), post-FY 2010 any CF/CT load that is made actual by expansions of the load must be placed at the bottom of the chronological stack, not the top, and cannot be treated as new load growth. *Id.* at 8.

GP and ICNU cite legislative history to assert that section 7(b) must be read to require preference customers to be served at the lowest firm power rate based on BPA's lowest-cost resources and, according to a House report, a higher rate will be applied to load growth of IOUs and to serve NLSLs. GP Brief, TRM-12-B-GP-01, at 6-7; ICNU Brief, TRM-12-B-IN-01, at 7. GP claims that the legislative history indicates that BPA must reserve the lowest rate for CF/CT load that a preference customer may have as load growth and that such nonexistent load must be treated on the same terms as its actual general requirements load, under a uniform, lowest rate. GP Brief,

TRM-12-B-GP-01, at 7-8. GP adds that calling Tier 2 a PF rate does not suffice for authority to tier rates. *Id.* at 8.

ICNU argues that “the right to service as a CF/CT load is guaranteed to both the industrial load and the preference utility customer” and provides assurance to the load that service will not be provided at the cost of new resources. ICNU Brief, TRM-12-B-IN-01, at 7, *citing* BPA NLSL Policy Issue Review at 14. ICNU claims that Tier 2 Rates charged to new CF/CT load will be similar to or same as the NR rate and based on the same pool of resources, making the CF/CT rights for unused load “essentially worthless.” *Id.* at 8, *citing* Wolverton, TRM-12-E-IN-01, at 11. ICNU states that the right to purchase power at a PF rate is meaningless if the PF rate for CF/CTs is essentially the same rate as for NLSLs. *Id.* at 13.

On the other hand, the PPG, joined by Canby Utility Board and Grays Harbor PUD, reaffirms its position stated in testimony that unrealized CF/CT load should *not* be considered in establishing customers’ rights to low-cost Federal power, consistent with BPA’s position. PPG Brief, TRM-12-B-PPG-01, at 26, *citing* Joint Rebuttal, TRM-12-E-PPG-02, at 9-10; Canby Joinder, TRM-12-M-CA-01; Grays Harbor Joinder, TRM-12-M-GH-01. In their joint brief, NRU and PNGC argue that service to post-FY 2010 CF/CT load at Tier 1 Rates would be special rate protection not afforded other preference customers and would create uncertainty for customers regarding eligibility to purchase at Tier 1 rates and the costs associated with that service. NPJ Brief, TRM-12-B-NPJ-01, at 2-4.

BPA Staff’s Position

BPA Staff proposed that BPA would serve and apply tiered rates only to actual existing retail load of a customer. Like all other customer load growth that may be placed on BPA in the future that is eligible for service at BPA’s PF rate, increases in the amount of CF/CT load that BPA’s customers are obligated to serve after September 30, 2010, will be subject to the applicable PF rate. Stene, *et al.*, TRM-12-E-BPA-18, at 3. When determining the future applicable PF rate, it is not necessary to adjust the TRM to account for unused amounts of CF/CT load or to increase a customer’s CHWM. *Id.* at 3-4.

Evaluation of Positions

Clatskanie, GP, and ICNU contend that the TRM will interfere with the alleged right that unrealized CF/CT load, including general requirements load growth, has to be served at the lowest cost-based PF rate. Clatskanie Brief, TRM-12-B-CK-01 at 7-9; GP Brief, TRM-12-B-GP-01, at 7-8; ICNU Brief, TRM-12-B-IN-01, at 8-9, 12-13. These parties contend that application of a Tier 2 Rate based on the cost of power BPA incurs to serve load that is above a customer’s RHWM, including unrealized expansion of CF/CT load, would subject such unrealized CF/CT load to a higher PF rate. *Id.* In turn, these parties contend such unrealized CF/CT load would be treated like an NLSL, because the PF rate would be based on unmixed power costs, making the rate treatment more like BPA’s marginal cost-based NR rate. *Id.*

The arguments raised by these parties have no merit. First, BPA does not serve or apply rates to unrealized load. It is not true, as ICNU contends, that a CF/CT determination made by the

Administrator creates a present right to power or to receive only the lowest-cost PF rate for such unrealized, nonexistent load. To the contrary, once CF/CT is determined, an amount of load is identified as a floor for measurement of increase in the consumer load. It is not a promise of service, and any actual CF/CT load is simply treated as part of the utility customer's general requirements load. Such actual load is served with BPA power sold at the applicable PF rates, and the CF/CT load gains no greater rights to service than the rest of the utility customer's general requirements load. By treating the CF/CT load as part of a utility's general requirements load, BPA will not be treating that load as an NLSL. As such, the CF/CT load will not constitute an amount of load of the utility that is served at the NR rate. *See* 16 U.S.C. § 839e(b)(4); "Subsection 7(b)(4) defines 'general requirements' as power used by the relevant customers under section 5(b), exclusive of power used by the customer to serve any new large single loads This provision thus affects power rates only, not the amount of power supplied to the customer under section 5(b)." H.R. Rep. No. 96-976, Part II, 96th Cong. 2d Sess., 52 (1980).

Second, as evaluated above in Issue 2, BPA has the authority to establish, pursuant to sections 7(b)(1) and 7(e) of the Northwest Power Act, more than one PF rate. As discussed above, BPA has the authority to tier the PF rate in accordance with section 7(b)(1), which results in more than one PF rate. The section 7(e) rate directive is clear that the Administrator is not required to establish a particular rate design, although the rates must recover BPA's total costs.

Third, nothing prohibits BPA from allocating, within the PF rate pool, the cost of additional power BPA is obligated to acquire to serve the general requirements of BPA's public body, cooperative, and Federal agency customers in order to better reflect cost causation and to send effective marginal cost price signals. Thus, the TRM will provide for the establishment of tiered PF rates of general application, consistent with the express language of the statute. 16 U.S.C. § 839e(b)(1). If CF/CT load amounts actually increase after the utility customer begins taking power deliveries under the new contract, the PF tiered rate design proposed in the TRM will ensure that the proper PF rate is determined and applied. *Stene, et al.*, TRM-12-E-BPA-18, at 4. No rate is reserved for service to unrealized, nonexistent CF/CT load.

Additionally, as BPA Staff noted in the evidentiary portion of the 7(i) proceeding, the rate treatment that ICNU advocates would provide a superior rate treatment to the serving utility for CF/CT load than exists under current melded rates, since the costs of serving load growth will not be included in the Tier 1 Rates. *Stene, et al.*, TRM-12-E-BPA-18, at 6. Further, load growth in Clatskanie's service territory over the next two years will increase Clatskanie's HWM, so load growth at GP over the next two years will be unaffected by the issue it has raised. *Id.* at 7. Finally, to the extent Clatskanie has "headroom" under its RHWM after FY 2010, GP load growth occurring after FY 2010 would be served at a retail rate set by Clatskanie that (presumably) reflects the Tier 1 Rates, while NLSLs occurring after FY 2010 will still be served at the NR rate. *Id.* This is so whether or not the utility has "headroom" under its RHWM.

ICNU states that the right to purchase power at a PF rate is meaningless if the PF rate for CF/CTs is essentially the same rate as for NLSLs. ICNU Brief, TRM-12-B-IN-01, at 13. Tier 2 Rates and NR rates are not the same, as alleged by ICNU. The Tier 2 Rates are a part of the PF rate, which is allocated the costs of first the FBS, then section 5(c) resources, and then, as needed, new resources. Further, the PF rate is eligible for section 7(b)(2) rate protection. The

NR rate is allocated FBS or section 5(c) resource costs only if such resources are surplus to the needs of the section 7(b) rate pool. Generally, there is no surplus, and the NR rate will be allocated the costs of new resources. Further, section 7(b)(3) exposes the NR rate to paying for the rate protection afforded preference customers through the application of section 7(b)(2). For example, the section 7(b)(3) rate surcharge for the NR-07R rate is \$8.80 per megawatt-hour. Thus, even if the resource costs incurred by BPA to serve an Above-RHWM Load and an NLSL were identical, the rates for the two loads would be distinctly different.

Decision

Future CF/CT load will not be included as an adjustment to a customer's CHWM in FY 2010 and thus will not be guaranteed service at the Tier 1 Rates.

Issue 4

Whether the TRM's allowance for adjustment of CHWM for DOE-Richland and New Publics is discriminatory and arbitrary and capricious because the unrealized, nonexistent CF/CT load of other preference utilities is not accorded the same adjustment.

Parties' Positions

Clatskanie, joined by EWEB and GP, argues that unrealized, nonexistent CF/CT load has a greater statutory right to service than DOE-Richland and New Publics' load growth, because the unrealized, nonexistent load is deemed already to exist by statute. Clatskanie Brief, TRM-12-B-CK-01, at 8-9; EWEB Joinder, TRM-12-M-EW-01; GP Joinder, TRM-12-M-GP-01. Clatskanie states that BPA gives no rational explanation for the discriminatory treatment, making it arbitrary, capricious, and with no support in the Northwest Power Act. Clatskanie Brief, TRM-12-B-CK-01, at 9.

GP claims that BPA must treat the Department of Energy comparably with every other customer that has a CHWM. GP Brief, TRM-12-B-GP-01, at 20. GP contends that BPA has provided no evidence showing that providing power at Tier 1 Rates for DOE-Richland growth after FY 2010 is critical to DOE-Richland's mission. *Id.* GP contends that it is discriminatory to increase CHWM for DOE-Richland while denying this treatment for other CF/CT load, particularly since DOE is a Federal agency and not a preference customer. *Id.* Similarly, GP claims that service to New Publics at Tier 1 Rates is also discriminatory, since they have not previously had access to power at Tier 1 Rates. *Id.* at 21.

ICNU contends that supplying DOE-Richland (labeled by ICNU as CF/CT load) load growth at Tier 1 Rates is inequitable, discriminatory, arbitrary and capricious. ICNU Brief, TRM-12-B-IN-01, at 10. ICNU states that DOE-Richland is far less price-sensitive than industrial customers, and there is no evidence in this proceeding that DOE-Richland will not increase its load if it is charged a Tier 2 Rate. *Id.* at 11. Regarding BPA's "national government use" rationale, ICNU notes that CF/CT treatment is provided for public body, cooperative, IOU, or

Federal agency customers with no preference, pursuant to Northwest Power Act section 3(13)(A), and there is no statutory basis to prefer one CF/CT load over another. *Id.*

BPA Staff's Position

BPA Staff cites the RD Policy ROD decision to augment for an increase in CHWM to include load at DOE-Richland for meeting national security interests that exist at the DOE spent uranium facilities in Richland. Stene, *et al.*, TRM-12-E-BPA-18, at 6. BPA, as part of the Federal government and within the U.S. Department of Energy, anticipates a potential increase in load at DOE-Richland for the critical strategic and public-interest mission of radioactive waste disposal at the DOE-Richland facility. *Id.*

Evaluation of Positions

Clatskanie argues that unrealized, nonexistent CF/CT load has a greater right to service at Tier 1 Rates than other general requirements load, such as DOE-Richland and New Publics, because, Clatskanie argues, all such load must “be treated as if it as existed since the passage of the Act.” Clatskanie Brief, TRM-12-B-CK-01, at 7.

BPA disputes the assertion that unrealized load exists simply because it has been determined to be CF/CT. A CF/CT amount is not a determination that actual load exists unless there is actual load that can be metered and measured. The portion of CF/CT load that has not materialized is not actual load that can receive service; there is no load that is consuming electricity. Unrealized, nonexistent CF/CT load has no right to Federal power at Tier 1 Rates, because it does not exist.

Additionally, the Northwest Power Act provides that the Administrator determines, based on 1979 information, whether an amount of customer load qualifies as a CF/CT load. 16 U.S.C. § 839a(13)(A). The result is a ceiling amount of load that is included in the CF/CT determination; however, if the consumption of electricity by the actual load is below the ceiling amount, it does not mean the nonconsuming amount of load exists. Rather, it means that once consumption of electricity increases, the amount of load under the CF/CT ceiling amount will be included in the utility's general requirement load that BPA serves at a PF rate. An unrealized, nonexistent load cannot be equated with actual load in determining the status of this ceiling amount, and BPA will not set aside power at Tier 1 Rates for such unrealized, nonexistent load. As a matter of policy, and consistent with BPA's broad authority to design and establish PF rates, BPA finds that it is reasonable to acquire additional power in the future and to include such costs in the Tier 1 Rates for New Publics and DOE-Richland by adjusting the HWMs of these entities.

Turning to the parties' specific arguments surrounding DOE-Richland, Staff testified that meeting the load growth of DOE-Richland is an important matter of meeting national security interests. Stene, *et al.*, TRM-12-E-BPA-18, at 6. The testimony on the record refutes GP's claim that no evidence was shown why providing power at Tier 1 Rates for DOE-Richland load growth after FY 2010 is critical to DOE's mission. The critical mission that is met in making the adjustment for DOE is “the critical strategic and public-interest mission of radioactive waste

disposal at the DOE-Richland facility.” Stene, *et al.*, TRM-12-E-BPA-18, at 6. This reason, standing alone, is sufficient to justify BPA’s decisions.

Moreover, in rebuttal testimony, Staff distinguished the case of DOE-Richland from that of an end-use consumer that constitutes a CF/CT load that has never developed its facility to take all of its CF/CT ceiling amount, noting that “there is significant uncertainty that it [the CF/CT load] will ever consume the full amount.” Stene, *et al.*, TRM-12-E-BPA-18, at 4. Staff examined direct testimony by ICNU, and that testimony merely illustrated the amounts of CF/CT load at consumers’ facilities that have never taken the full CF/CT ceiling amount in over 25 years. *Id.* This information supports a conclusion that unrealized CF/CT load may never actually consume electricity.

In stark contrast, construction of facilities at DOE-Richland is occurring and has a specific completion date. In particular, the energization of those facilities will likely increase the energy consumption within the DOE CF/CT load ceiling amount by FY 2010. BPA explained in the RD Policy ROD that nuclear waste treatment facilities are currently under construction at the site. Such construction was slowed in 2005 and halted temporarily on two primary power use facilities (high level waste and pretreatment facilities) due to seismic and budget concerns. Other waste treatment construction activities continue, however. RD Policy ROD at 39-40. These facts demonstrate that the adjustment BPA will make in the HWM for DOE is reasonable, because actual investment is being made and Federal dollars are being expended.

Additionally, Federal agencies are subject to Northwest Power Act section 3(13) just as any other customer of BPA. BPA’s rate directives clearly provide that Federal agencies, just like preference customers, are subject to rates of general application established pursuant to section 7(b)(1) of the Northwest Power Act. 16 U.S.C. § 839e(b)(1). The application of preference under the TRM, a rate methodology, is not an issue, because preference protects preference customers’ access to power supply, not price. *Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037, 1046 (9th Cir. 2007). There is no dispute over the *availability* of Federal power to be supplied during the term of the TRM. Sufficient power will be acquired to serve both CF/CT load (if it is developed at all) and DOE-Richland. Therefore, the Administrator, in deciding to allow an adjustment in DOE-Richland’s HWM, is deciding a rate issue and not a power supply issue for an actual load. In making this decision, the Administrator considered issues of national security, nuclear waste management, Federal agency status under Northwest Power Act section 3(13), and actual construction and timing of the load.

Similarly, BPA’s future treatment of New Publics was addressed in the RD Policy ROD and is based on BPA’s contract requests over the past 25 years from new public utilities that formed in the region. BPA does not agree that its treatment is arbitrary, unreasonable, or discriminatory. BPA’s RD Policy ROD articulates the underlying policy rationale for providing HWMs for New Publics, which is to make Federal power at Tier 1 Rates more widely available while providing planning certainty for the amount of power that BPA may need to acquire to serve New Publics in the future. *See* RD Policy ROD, at 80. One of BPA’s ratesetting requirements is to encourage the widest possible diversified use of electric power. *Id.*, *citing* 16 U.S.C. § 838g.

Consistent with this statutory directive, BPA has historically allowed a reasonable period of time for the formation of a new public utility and its acquisition of a retail distribution system so that the new utility is ready, willing, and able to take power service. BPA's approach is consistent with sections 4(c) and 4(d) of the Project Act and DOE's General Counsel Opinion, "Request of City of Needles for Reinstatement of Sales of Federal Power for Benefit of its Citizens" (Nov. 21, 1978). The DOE policy was affirmed in *Salt Lake City, et al., v. Western Area Power Administration*, 926 F.2d 974 (10th Cir. 1991). As stated in the RD Policy ROD,

BPA believes that excluding new publics from an opportunity to obtain power at the Tier 1 rate would place them in an unfavorable position and would not promote the widest possible use of Federal power; however, BPA also wishes to ensure utilities receive price signals that more directly signal the true incremental costs of load growth.

RD Policy ROD at 81. As proposed, New Publics will have an opportunity to receive some amount of their general requirement power at Tier 1 Rates. Currently unrealized, nonexistent CF/CT load, if it occurs, will be general requirement load of a utility served at a Tier 2 Rate, and the utility will purchase that power along with power priced at the Tier 1 Rates. A New Public, once it qualifies for service, will also be able to have a portion of its load served at the Tier 1 Rates. This treatment will level the playing field for service between Existing Publics and New Publics. Likewise, once any of the New Public's load reaches its HWM, any additional service for general requirements power will be subject to the applicable Tier 2 Rate(s). As such, the TRM's treatment for New Publics is reasonable and comparable to that for all other Publics.

Decision

The TRM's allowance for adjustment of CHWM for DOE-Richland and New Publics is not discriminatory, arbitrary, or capricious.

Issue 5

Whether BPA committed to serve CF/CT loads at the lowest rate available to preference customers, the Tier 1 Rates.

Parties' Positions

Clatskanie, joined by EWEB and GP, argues that preference customers with CF/CT loads have reasonably relied on BPA's contractual commitment to serve these loads at the lowest rate made available to preference customers, the Tier 1 Rates. Clatskanie Brief, TRM-12-B-CK-01, at 10; EWEB Joinder, TRM-12-M-EW-01; GP Joinder, TRM-12-M-GP-05; Booth, TRM-12-E-CK-01, at 5. Clatskanie argues that BPA is now estopped from changing its treatment of CF/CT load in the TRM. Clatskanie Brief, TRM-12-B-CK-01, at 10.

BPA Staff's Position

Because this is a legal issue, BPA Staff did not address this issue in the evidentiary portion of the proceeding.

Evaluation of Positions

Clatskanie notes that the CF/CT designation for its Wauna mill (Wauna) was made August 30, 1982, and has been recognized by contracts between Clatskanie and BPA ever since. Clatskanie Brief, TRM-12-B-CK-01, at 10. Clatskanie claims that BPA did not include in Clatskanie's CHWM Wauna's yet-to-be-realized CF/CT load of approximately 40 aMW. *Id.* Clatskanie claims that the TRM would prohibit Clatskanie from acquiring power from BPA at Tier 1 Rates to serve potential increases in the load at Wauna. *Id.* Clatskanie would thus have to either buy power at a Tier 2 Rate from BPA or buy power for itself at market rates at a cost similar to the NR rate for NLSLs. *Id.* Clatskanie claims that, relying on BPA's CF/CT determination, Clatskanie constructed infrastructure and facilities with the expectation of serving the entire Wauna CF/CT load amount at the lowest rate made available to BPA's preference customers. *Id.* As an example, Clatskanie states that it purchased a substation from BPA to serve Wauna with the capacity to serve CF/CT load up to 140 aMW and has made over \$3 million in capital improvements to the substation. *Id.* Clatskanie claims that if load does not materialize as a direct result of the rate treatment proposed by the TRM, Clatskanie may incur stranded costs and significant economic damages. *Id.*

First, Clatskanie's reliance on Wauna's CF/CT designation is unreasonable—Clatskanie has misconstrued the effect of that designation. The designation of a CF/CT, as previously noted, creates only an obligation on BPA to serve such load as part of a utility customer's general requirements. A CF/CT designation does not guarantee price. It is not true, as Clatskanie contends, that a CF/CT determination creates a right to receive power only at the lowest PF rate (the Tier 1 Rates). To the contrary, once a large load is determined to be CF/CT and the ceiling amount of load is set, the realized actual CF/CT load is treated simply as part of the utility customer's general load. However, unrealized nonexistent CF/CT load is not served. The actual load is served with requirements power sold by BPA at the applicable PF rates, and the CF/CT load gains no greater rights to service than the rest of its serving utility's actual load. Including the CF/CT determined actual load as part of a utility's general requirement load means the actual amount of load is not treated as an NLSL and thus is not served at the NR rate. *See* 16 U.S.C. § 8393(b)(4); H.R. Rep. No. 96-976, Part II, 96th Cong. 2d Sess., 52 (1980). The only aspect of Wauna's CF/CT designation on which Clatskanie could reasonably rely is the requirement that BPA will make power available to Clatskanie to serve that load at a PF rate, but not at a guaranteed lowest-cost PF rate, particularly, since BPA enjoys rate design discretion. 16 U.S.C. § 839e(e); *City of Seattle v. Johnson*, 813 F.2d 1364, 1367 (9th Cir. 1987); *Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 1121-22 (9th Cir.1984).

Second, as a matter of law, BPA's rate directives require that BPA establish and periodically review and revise its rates. 16 U.S.C. § 839e(a)(1). BPA's power sales contracts, including all those with Clatskanie, have always reflected the requirement that BPA periodically revise its rates for power service. Accordingly, Clatskanie cannot have justifiably relied on BPA's PF rate

levels not changing or BPA's rate designs not being modified. BPA, in setting rates, routinely modifies its rate designs and in the past has considered the possibility of tiering its rates. Notice of Proposed Wholesale Power Rate Adjustment, 60 Fed. Reg. 8496, at 8497-98, 8503-04 (Feb. 14, 1995) ("BPA is proposing to divide its priority firm (PF) and industrial firm power (IP) rates into two tiers, (Tier 1 and Tier 2) and to establish separate rates for each tier."). Clatskanie therefore cannot have reasonably relied upon rates or rate designs that Clatskanie knew were subject to periodic review and re-design by BPA through a section 7(i) proceeding. Even if Clatskanie believes in the face of an earlier BPA rate tiering proposal that it never foresaw the potential of tiered rates, it has not pointed to any contractual provision to serve these loads at the lowest rate made available to preference customers that supports its argument, presented in testimony, that Clatskanie reasonably relied on BPA not to adopt tiered rates. Booth, TRM-12-E-CK-01, at 5. The TRM was proposed and developed only in the past year, and it is therefore impossible for Clatskanie to have developed any historical reliance on service at the Tier 1 Rates.

Third, it is reasonable for BPA to limit the augmentation of the Tier 1 System Resources for purposes of additional CHWM. One of the primary purposes behind the decision to tier the PF rates is a desire to preserve the value of the Tier 1 System Resources. RD Policy, at 6. To accomplish this, BPA decided to limit the amount of additional augmentation it would provide for the purpose of adding to the CHWMs for utilities. The circumstances under which BPA will augment the Tier 1 System for CHWMs are outlined in section 3.2 of the TRM. BPA believes that unrealized, nonexistent CF/CT load that actually comes on line after FY 2010 should not be treated any differently from the other general requirement load growth of any other preference utility. It is certainly reasonable for BPA to exclude in a CHWM determination any customer load that is not in existence and hence not consuming power.

Fourth, Clatskanie acknowledged that since Wauna's CF/CT and ceiling load amount were determined in 1982, Wauna's energy consumption has never increased to the full ceiling amount, which leaves 40 aMW of potential unrealized load nonexistent and unserved. Clatskanie Brief, TRM-12-B-CK-01, at 10. This 40 aMW of CF/CT load is not consuming electricity because it was never developed, and its nonexistence is certainly not due to BPA's proposed TRM. Because Clatskanie, GP, and ICNU raise these issues only in their briefs, they have offered no evidence on the record for BPA to address, refute, or rebut regarding the reasons why the multiple owners of Wauna did not expand the facility or why such consumption has not occurred during more than 26 years of operation. The bottom line is that BPA serves only actual load and not yet-to-be-realized load. This failure to grow into the unrealized amount was not caused by the TRM proposal or its design.

Fifth, Clatskanie claimed that it made significant investments in infrastructure in anticipation of this additional load and points to its acquisition of the Wauna substation from BPA and upgrades. Clatskanie Brief, TRM-12-B-CK-01, at 10. Clatskanie acquired the substation in 1996, almost 12 years ago, and no expansion of load has occurred since then. It is not clear that Clatskanie made these infrastructure investments in anticipation of future loads as opposed to other changes to the Wauna mill, including replacement of existing machinery, that have already been completed. Even if some of Clatskanie's investment was done in anticipation of future and nonexistent loads, those costs should already be embedded in Clatskanie's current rates and should not result in any significant economic detriment. Finally, Clatskanie's argument is

inapposite because of the type of contract under which it purchases power from BPA. BPA notes that since 2001 Clatskanie has purchased its firm power from BPA under a Slice/Block contract. Under the terms of this contract, as well as the current offering of this product, BPA's obligation to sell firm power to Clatskanie is limited, and power is delivered as a percentage of output generated in the shape of the Federal system. As such, Clatskanie is obligated to acquire Non-Federal Resources to meet the increased load growth needs of its retail consumers beyond the amount of Federal power supplied by BPA under the Slice/Block contract. Purchases by Clatskanie of Non-Federal Resources, i.e., from the market, more than likely will result in costs higher than the cost of Federal power. Given this, Clatskanie's argument that it justifiably relied on BPA's low cost-based rates to meet future load growth is without firm foundation.

Decision

Contrary to Clatskanie's assertion, BPA did not commit to serve CF/CT loads at the lowest rate available to preference customers, the Tier 1 Rates. CF/CT treatment of new load guarantees service but is not a commitment to service at the lowest PF rate.

Issue 6

Whether the TRM will foreclose utilities from adding CF/CT load in the future.

Parties' Positions

ICNU contends that the TRM will arbitrarily close out the class of customers eligible to place CF/CT loads on BPA and receive low-cost power. ICNU Brief, TRM-12-B-IN-01, at 13.

BPA Staff's Position

This issue was not addressed in the evidentiary portion of the 7(i) proceeding and is raised for the first time on brief.

Evaluation of Positions

ICNU correctly notes that BPA previously queried parties whether to administratively close out the CF/CT class by imposing a cut-off date. See New Large Single Load Policy Issue Review Administrator's Record of Decision (March 2002) (NLSL Policy ROD). BPA concluded that section 3(13) of the Northwest Power Act does not grant the Administrator the discretion to take such administrative action and noted that the provision does not place a time bar on the CF/CT class. *Id.* at 14. ICNU contends that the TRM will impose a time bar on CF/CT status by requiring all CF/CT loads to obtain service by FY 2010 or be treated essentially the same as NLSLs. ICNU Brief, TRM-12-B-IN-01, at 13.

It is not true that the TRM will result in any time limitation on a utility's request of the Administrator to determine a load's CF/CT status. The operation of section 3(13) of the Northwest Power Act will continue during the term of the TRM and beyond, subject only to an

act of Congress. As stated in the NLSL Policy ROD, once a load has been determined as CF/CT there is an assurance that BPA service within the CF/CT load amount will be subject to the then-effective PF rates. NLSL Policy ROD at 14. The TRM proposes no time limit on BPA's determination of CF/CT loads under section 3(13). The Administrator's determination of whether a load is a CF/CT load under that section of the Act remains as it has been. ICNU is simply seeking a lower price.

It is unreasonable to argue, as ICNU does, that the service to future CF/CT load will be "essentially the same as NLSLs." ICNU Brief, TRM-12-B-IN-01, at 13. Such a conclusion is unfounded: CF/CT load is part of the utility customer's general requirements load that is served with requirements power. The TRM does not preclude BPA's utility customers from requesting a CF/CT load determination by the Administrator or preclude them from taking service at the PF rates applicable to such service. They are also not forced to make such requests by FY 2010. Whenever CF/CT load is once determined by the Administrator and served, it will be general requirements load that is served with power sold at the applicable PF rate, including its particular rate form or rate design. Therefore, the TRM does not establish any time bar.

The TRM also does not result in CF/CT load being treated essentially the same as NLSLs. If realized, future CF/CT load will become part of a utility's general requirements. BPA will sell to such general requirements at the applicable PF rates, including the Tier 2 Rates, developed in accord with section 7(b) of the Northwest Power Act. If realized, future NLSL load would be subject to the NR rate, developed in accord with section 7(f) of the Northwest Power Act.

Decision

The TRM will not foreclose utilities from adding CF/CT load in the future.

Issue 7

Whether a customer that signs a CHWM Contract is being deprived of its due process rights.

Parties' Positions

Clatskanie, joined by McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, and GP, contends that forcing Clatskanie and other preference customers to execute post-FY 2011 power sales contracts is problematic. Clatskanie Brief, TRM-12-B-CK-01, at 14; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; GP Joinder, TRM-12-M-GP-05. Clatskanie claims that if BPA does not modify the TRM to allow for service of Wauna's entire CF/CT load at Tier 1 Rates, Clatskanie will be forced to make a difficult decision: (1) execute a contract that does not recognize that the entire Wauna CF/CT load is entitled to service at the Tier 1 Rates and, in effect, arguably waive the rights afforded to Wauna's CF/CT status; or (2) refuse to execute a contract because executing would constitute a waiver of Wauna's CF/CT right to lowest-cost rate treatment and therefore jeopardize its statutory right to purchase any power at Tier 1 Rates. Clatskanie Brief, TRM-12-B-CK-01, at 14.

BPA Staff's Position

This issue is raised for the first time on brief. BPA Staff did not address this issue in the evidentiary portion of the 7(i) proceeding.

Evaluation of Positions

Staff has explained the proposed rate treatment for CF/CT load that is actual load, and the treatment for expansion of load at a consumer's facility if it is ever "realized." BPA is not requesting a waiver for CF/CT load, and Clatskanie is unable to waive a right of service at a specific rate to a load that does not exist and may never exist. All BPA public utility customers will face a choice about the execution of new contracts; Clatskanie is not unique. The fact that Clatskanie is faced with a potentially difficult choice does not implicate Clatskanie's due process rights, especially given the exhaustive administrative processes that pertain to BPA's development of contracts and the 7(i) proceeding for the development of tiered rates methodology.

The issue raised by Clatskanie over what could be a difficult contract decision for Clatskanie is not a proper issue for resolution in this TRM 7(i) proceeding. The TRM's rate treatment for CF/CT load is properly raised in this forum, and those issues have been addressed above. Such issues pertain to the proposed establishment of rates applied to BPA power sold under the new CHWM Contracts. The negotiation of contract terms has not been conducted as part of this 7(i) proceeding; nor would such contract negotiation be properly included in a 7(i) proceeding. BPA's determination of rate issues is governed by section 7 of the Northwest Power Act and is separate from the terms and conditions of the power sales contracts.

Decision

BPA addresses Clatskanie's concerns regarding whether a customer that signs a CHWM Contract is being deprived of its due process rights in BPA's Regional Dialogue Contract Policy Record of Decision at 36-38.

Issue 8

Whether the TRM results in an unconstitutional taking of property from Georgia-Pacific.

Parties' Positions

GP argues that BPA's failure to protect CF/CT loads in its TRM proposal results in a "regulatory taking" of GP's contract-based property rights for which GP must receive compensation.⁹

⁹ GP makes this argument under the broader heading of "CF/CT CONSUMERS HAVE A LEGAL INTEREST WHICH IS HARMED BY THIS PROPOSED RATE." GP Brief, TRM-12-B-GP-01, at 11 (emphasis added). However, nowhere in the argument does GP address CF/CT "consumers" as a general group. Instead GP's argument is limited exclusively to GP's specific situation. *Id.* at 11-20. Moreover, GP is the only CF/CT consumer

GP Brief, TRM-12-B-GP-01, at 11. GP's logic is that under GP's contract for electric service with Clatskanie PUD, GP can currently obtain service for its Wauna mill up to its CF/CT load level at rates based on BPA's lowest preference rate. *Id.* at 12. GP characterizes this contractual provision between it and Clatskanie as a "property right," which GP believes will be severely devalued by BPA's implementation of a tiered rate structure. *Id.* According to GP, tiered rates would result in higher energy costs for certain CF/CT loads, and those costs would significantly reduce the incentive of GP to expand its operations at Wauna, and undermine the value of the mill itself. *Id.* Thus, GP concludes, the TRM will effect a regulatory taking of GP's property rights, and therefore GP is entitled to just compensation for this devaluation. *Id.*

BPA Staff's Position

Because this is a purely legal argument set forth in briefing, BPA Staff has not taken a position. BPA's legal position on this issue is set forth below.

Evaluation of Positions

GP's takings argument has numerous fundamental flaws, any one of which independently invalidates it. First, for purposes of the Fifth Amendment, GP has no legally cognizable property interest. Second, even if GP had a valid property interest, its alleged loss is merely consequential and not one for which takings law affords a remedy. Third, GP's claim fails the *Penn Central* standards for establishing a regulatory taking. Finally, the remedy GP is seeking is not available under the law of takings. BPA will address each of these areas in turn.

The Takings Clause of the Fifth Amendment provides that "private property [shall not] be taken for public use, without just compensation." U.S. Const. amend. V, cl. 4. It is "designed not to limit the governmental interference with property rights *per se*, but rather to secure *compensation* in the event of otherwise proper interference amounting to a taking." *First English Evangelical Lutheran Church of Glendale v. County of Los Angeles*, 482 U.S. 304, 315 (1987) (emphasis in original). "The purpose of the takings clause is to prevent 'Government from forcing some people alone to bear public burdens which, in all fairness and justice, should be borne by the public as a whole.'" *Air Pegasus of D.C., Inc. v. United States*, 424 F.3d 1206, 1212 (Fed.Cir. 2005) (quoting *Penn Cent. Transp. Co. v. City of N.Y.*, 438 U.S. 104, 123, 98 S.Ct. 2646, 57 L.Ed.2d 631 (1978)).

The Supreme Court has recognized two kinds of compensable takings: (1) actual takings, through the Government's physical invasion or appropriation of private property, and (2) regulatory takings, through government regulations that unduly burden private property interests. See *Huntleigh USA Corp. v. United States*, 525 F.3d 1370, 1378 (Fed.Cir. 2008). GP alleges a regulatory taking.

To analyze GP's regulatory taking claim, the law applies "a two-part test for determining whether 'fairness and justice' require compensation for burdens imposed by a particular

to advance this novel theory, and no other CF/CT consumers have joined or supported this section (or any section) of GP's Brief. Accordingly, this ROD addresses the argument solely with respect to the facts surrounding GP's situation.

governmental action.” *Huntleigh*, 525 F.3d at 1377. As the first step, the court must determine whether the claimant has established a legally cognizable property interest for purposes of the Fifth Amendment. *Id.*; *see also Yuba Natural Res., Inc. v. United States*, 904 F.2d at 1577, 1581 (Fed.Cir. 1990) (“It is a well settled principle of Fifth Amendment Taking law, however, that the measure of just compensation is the fair value of what was taken, and not the consequential damages the owner suffers as a result of the taking.”). Second, after the court has identified a valid property interest, it must determine whether the government action at issue amounted to a compensable taking of that property interest. *Huntleigh*, 525 F.3d at 1378; *Am. Pelagic Fishing*, 379 F.3d at 1372; *Engquist v. Or. Dep’t of Ag.*, 478 F.3d 985, 1002 (9th Cir. 2007) (“We use a two-step analysis to determine whether a “taking” has occurred: first, we determine whether the subject matter is “property” within the meaning of the Fifth Amendment and, second, we establish whether there has been a taking of that property, for which compensation is due.”). However, if the claimant fails to demonstrate the existence of a legally cognizable property interest, the court does not proceed with this second step. *Air Pegasus*, 424 F.3d at 1213.

I. GP does not have a legally cognizable property interest that has suffered a taking as a result of the TRM.

GP alleges a regulatory taking of its contract-based property rights. GP Brief, TRM-12-B-GP-01, at 11. Although contracts, leases, and other agreements may be considered property within the meaning of the Fifth Amendment, the Government’s appropriation of which may trigger the resulting obligation to pay just compensation, “not every exercise of governmental power that interferes with, or frustrates, performance of a contract constitutes a compensable taking.” *Kearney & Trecker Corp. v. United States*, 231 Ct.Cl. 571, 688 F.2d 780, 783 (Cl.Ct. 1982) (citing *Lynch v. United States*, 292 U.S. 571, 579, 54 S.Ct. 840, 78 L.Ed. 1434 (1934) and *Omnia Commercial Co. v. United States*, 261 U.S. 502, 510-11, 43 S.Ct. 437, 67 L.Ed. 773 (1923)). To explain what constitutes a cognizable Fifth Amendment property interest, courts have distinguished between a plaintiff’s actual property and its “collateral interest.” *See, e.g., Air Pegasus*, 424 F.3d at 1215; *Mitchell Arms, Inc. v. United States*, 7 F.3d 212, 217 (Fed.Cir. 1993); *Schooner Harbor Ventures, Inc. v. United States*, 81 Fed.Cl. 404, 412-13 (2008). “The Fifth Amendment concerns itself solely with the ‘property,’ *i.e.*, with the owner’s relation as such to the physical thing and not with the other collateral interests which may be incident to his ownership.” *Mitchell Arms*, 7 F.3d at 217 (quoting *United States v. General Motors Corp.*, 323 U.S. 373, 378, 65 S.Ct. 357, 89 L.Ed. 311 (1945)).

Here, GP plainly admits that the only thing it has a “property right” in is its contract for electric service with Clatskanie PUD. GP Brief, TRM-12-B-GP-01, at 12, *see also id.* at 14. But that contract, GP contends, will supply GP with energy “at rates *based on* BPA’s lowest Preference Rate.” *Id.* (emphasis added). Because the rates in GP’s contract are “based on” the rates Clatskanie pays for its wholesale supply of power from BPA, GP believes that in the future BPA’s TRM proposal would have “consequences” in the form of increased energy costs passed through from Clatskanie to GP. *Id.* at 16. These future cost increases would in turn undermine the value of GP’s Wauna mill and remove the incentive to expand that facility. *Id.*

A similar claim arose where the PVM Redwood Company operated a sawmill and alleged that the passage of the Redwood Park Expansion Act, 16 U.S.C. § 79b *et seq.*, caused a taking of its

property by the United States. *PVM Redwood Co. Inc. v. United States*, 686 F.2d 1327, 1328 (9th Cir. 1982). PVM Redwood’s “alleged property right” was the fact that the “Secretary of the Interior had acquired ... timber lands owned by [individuals] who had in the past supplied 98% of PVM’s [raw material] requirements” and this acquisition “made it impossible for them to continue to meet PVM’s needs.” *Id.* As a consequence, PVM alleged that it had “suffered an increase in production costs... .” *Id.*

The problem with PVM’s claim was that it had “no ownership interest in its source of supply.” *PVM*, 686 F.2d at 1329. GP’s claim suffers from the exact same flaw. Like PVM, the regulation (the TRM) will not cause GP to be “denied use of its property; it can still run its ... mill.” *Id.* GP does not allege that it would be denied use of its contract with Clatskanie; it can still purchase power under that contract. Instead, GP’s claim is derivative in nature: that the *value* of its contract will decrease.

At most, the TRM will affect only the rate design used to establish the PF rate applicable to general requirements sold under the CHWM Contracts with BPA’s preference customers, including Clatskanie, GP’s retail supplier. In reality, there can be no actual taking, since what GP alleges is that a change in the rate applicable to power sold to Clatskanie constitutes the taking. Neither Clatskanie nor any other preference customers have property rights in a fixed price for power sold by BPA, because BPA by law must review and revise its rates at least once every five years. Further, the Northwest Power Act does not provide Clatskanie an alleged right to the “lowest preference rate” for its CF/CT customers such as GP. The Northwest Power Act does afford preference customers a PF rate or rates, and, as explained above, that is what BPA is providing customers under the TRM. GP’s supposed “economic injury is not the result of the government taking [its] property, but is the more attenuated result of the government’s purported taking of other people’s property.” *Air Pegasus*, 424 F.3d at 1215. GP plainly says that its contract rates are “based on” Clatskanie’s rates and that BPA’s TRM proposal would have “consequences” for GP in the form of increased energy costs passed through from Clatskanie to GP. GP Brief, TRM-12-B-GP-01, at 12, 16. To the extent this harm exists, it is a “derivative injury” that does “not form the basis for a viable takings claim.” *Air Pegasus*, 424 F.3d at 1215.

Indeed, GP could never claim a property interest in a contract with BPA because BPA has no statutory authority to contract with a retail consumer such as GP. Accordingly, it is impossible for GP to have a legally cognizable property interest in the supply of power from BPA to Clatskanie and the rates BPA establishes therefor. All that GP has is a collateral interest in the rates of its contract, which GP states are “based on” those of the contract between BPA and Clatskanie. GP Brief, TRM-12-B-GP-01, at 12, 14. Accordingly, GP does not meet the threshold test of having a legally cognizable property interest that has suffered a taking as a result of the TRM, and therefore GP’s argument fails for this reason alone.

II. Even if GP had a property interest, its alleged loss is merely consequential and not one for which takings law affords a remedy.

Assuming *arguendo* that GP has a property interest, the line of precedent starting with *Omnia Commercial Co., Inc. v. United States*, 261 U.S. 502 (1923), also precludes GP’s takings claim. The Supreme Court, beginning with *Omnia*, has held that a compensable taking can never occur

in cases where government actions caused a commercial loss from one private party to another, but did not actually take the contract in question. In *Omnia*, the plaintiff possessed a contractual right to purchase a large quantity of steel from the seller at a low fixed price. *Omnia*, 261 U.S. at 507. However, before the seller could deliver any steel to the plaintiff, the Government requisitioned the seller's entire production of steel plate for the year 1918, because of need for the war effort, and directed the seller not to fulfill its contract with the plaintiff. *Id.* The Court rejected the plaintiff's claim that the Government's action of requisitioning the seller's steel had effected a taking for public use of its property in the contract. *Id.* at 508, 514. While acknowledging the plaintiff's property interest in its contract, within the meaning of the Fifth Amendment, the Court nonetheless held that the plaintiff's loss was merely "consequential" and one for which takings law afforded no remedy. *Id.* at 510-11.

Although the plaintiff had suffered an undeniable loss, the Court declared that "destruction of, or injury to, property is frequently accomplished without a 'taking' in the constitutional sense." *Id.* at 508. The Court added that there are many laws and governmental regulations that injuriously affect the value of private property but for which no remedy is afforded. *Id.* at 508. In rejecting *Omnia's* takings claim, the Court noted that "[f]rustration and appropriation are essentially different things." *Id.* at 513, 43 S.Ct. 437.

This principle remains unchanged and has been affirmed in a wide variety of takings claims where the Government has caused the loss of the benefits of a contract or frustrated business expectations. In each of these cases, the plaintiff's economic interest was frustrated in that it failed to receive its expected compensation from private agreements as a result of the Government's actions. See *Air Pegasus*, 424 F.3d at 1209-10; *NL Indus. v. United States*, 839 F.2d 1578, 1579 (Fed.Cir. 1988). In *Air Pegasus*, the Federal Circuit aptly characterized the *Omnia* court's view on takings as finding a "significant difference between an *injury* to one's property interest and a *taking* of one's property interest." 424 F.3d at 1216.

Here, the most GP suggests is that the TRM may frustrate its business expectation (i.e., the full economic advantage it is expecting from its private agreement with Clatskanie), which does not amount to a compensable taking under the *Omnia* line of cases. Indeed, GP's takings claim is even less compelling than those of the plaintiffs in *Omnia* and *Air Pegasus*, because those plaintiffs at least had existing contracts that were directly and immediately impacted by the government's actions. GP has only a contract "based on" the BPA/Clatskanie contract, which is the actual contract that will be affected by the TRM. GP Brief, TRM-12-B-GP-01, at 14. Moreover, GP does not allege any present, immediate effects on its contract, only the possibility of future consequential increases in energy costs that may "undermine the value of [GP's] Wauna mill" and could remove "the incentive to expand that facility." *Id.* at 16. Under the same reasoning as *Omnia* and *Air Pegasus*, GP's claim fails because the TRM does not effectuate an immediate taking of the assets in question. *Omnia*, 261 U.S. at 513.

Perhaps anticipating this fatal flaw in its claim, GP argues that "there is no requirement that the contract at issue be one to which the party asserting the [takings] claim and the government are both parties" and cites as an example the case of *Cienega Gardens v. United States*, 331 F.3d 1319 (Fed.Cir. 2003).

Cienega is distinguishable from GP's situation for a variety of reasons. First, in *Cienega* the plaintiffs had contractually conferred rights sufficient to meet the Fifth Amendment property interest requirement. Namely, the plaintiffs had "unequivocal contractual rights after twenty years to prepay their mortgages; thus they had a property interest in those rights... ." *Cienega Gardens*, 331 F.3d at 1330. As discussed above, GP does not have a legally cognizable property interest for Fifth Amendment purposes.

Second, in *Cienega* the government action (the passage of two pieces of legislation) had an "immediate effect," namely, "to nullify the [plaintiffs' contractual] option to prepay their mortgage." *Id.* at 1327. As noted above, GP has not alleged any present, immediate effects on its contract, only the possibility of future, consequential increases in energy costs that may "undermine the value of [GP's] Wauna mill" and could remove "the incentive to expand that facility." GP Brief, TRM-12-B-GP-01, at 16.

Third, although the government was not a party to the contracts in *Cienega*, it was inextricably involved in setting their terms. *Cienega Gardens*, 331 F.3d at 1325. Specifically, Department of Housing and Urban Development (HUD) "reviewed, endorsed, and approved [the contracts] and their terms mirrored HUD regulations." *Id.* Here, there is no such entanglement between BPA and the contract between Clatskanie and GP. Nor has GP offered any evidence of such.¹⁰ In fact, just the opposite is true; Clatskanie's publicly available Official Statement plainly states that "[Clatskanie] is responsible for determining rates to be charged for its electrical service. The rates are not subject to approval or review by any other body." Clatskanie Official Statement, at 12.

Fourth, in *Cienega* the government action (enactment of two statutes) was "aimed at the contract rights themselves in order to nullify them." *Id.* at 1335. Because "[t]he enactment of [the statutes] directly and intentionally abrogated the contracts," the "effect on the contracts [was], therefore, not merely consequential." *Id.* As discussed above, this is a key distinction from GP's present situation. BPA has not taken any direct and intentional action toward GP's contract with Clatskanie. Rather, just like the *Omnia* line of cases, the effect on GP's contract is merely consequential (and even that is speculative).

Finally, and most importantly, in *Cienega* the plaintiffs' contracts were "taken" by the government for its own use and benefit, namely, to ensure that the plaintiffs would continue to have a duty to provide the low-income housing that the government sought to promote. *Id.* "Where Congress' actions have the effect of 'keeping the contract alive for the use of the government' rather than 'bringing the contract to an end,' a court should conclude that there *has* been a taking." *Id.*, quoting *Omnia*, 261 U.S. at 513. GP has made no assertion that BPA is somehow taking its Clatskanie contract for BPA's own use and benefit. Instead, GP alleges that BPA's actions only incidentally affect its contract rights.

¹⁰ GP points to BPA's general statement that "effects on [the Wauna] mill's ability to further expand are of concern to BPA" as some indication of BPA's knowledge or involvement with Clatskanie's contract with GP. This general statement hardly rises to the level of reviewing, endorsing, and approving the GP/Clatskanie contract.

III. Even if GP had a property interest, and if its loss was not merely consequential, it still fails the *Penn Central* standards for establishing a regulatory taking.

Regulatory takings challenges are governed by the standards set forth in *Penn Central Transp. Co. v. New York City*, 438 U.S. 104 (1978); *see also Lingle v. Chevron U.S.A., Inc.*, 544 U.S. 528, 538 (2005). “The Court in *Penn Central* acknowledged that it had hitherto been ‘unable to develop any “set formula” ’ for evaluating regulatory takings claims, but identified ‘several factors that have particular significance.’ ” *Lingle*, 544 U.S. at 538 (*quoting Penn Central*, 438 U.S. at 124). Those factors are: (1) “[t]he economic impact of the regulation on the claimant;” (2) “the extent to which the regulation has interfered with distinct investment-backed expectations;” and (3) the “character of the governmental action... .” *Penn Central*, 438 U.S. at 124.¹¹

1. Economic impact

GP suggests that it will incur approximately \$12 million per year in additional energy costs to serve the remaining 41.9 MW of its CF/CT capacity at Tier 2 Rates as opposed to Tier 1 Rates. GP Brief, TRM-12-B-GP-01, at 16. GP states that such increased costs would have “detrimental consequences” on the value of GP’s Wauna mill and the incentive to expand that facility. *Id.*

The suggestion that GP has suffered an economic impact from the TRM is highly speculative. First, GP has not and cannot demonstrate with certainty that it will use any more of its CF/CT designation than it is currently using. This load uncertainty means that application of a Tier 2 Rate may never come into play. GP testified that it would need “most” of its remaining CF/CT headroom because of “anticipated” growth and “projected” needs. Tompkins, TRM-12-E-GP-01, at 5. This is not the sort of concrete, present economic impact that is required by the first factor of *Penn Central*.

Second, GP will be unaffected for at least the next two years by the issue it has raised. This is because load growth in Clatskanie’s service territory over the next two years will increase Clatskanie’s HWM. Stene, *et al.*, TRM-12-E-BPA-18, at 7. This means Clatskanie has the opportunity to establish “headroom” within the amount of power that will be sold at the applicable Tier 1 Rate before it would be required to purchase power subject to the applicable Tier 2 Rate (or purchase Non-Federal Resources). *Id.* So, even if GP’s economic impact was concrete, it would not be immediate and would be avoidable by GP increasing its load on Clatskanie.

¹¹ Along with regulatory takings based on the three *Penn Central* factors, there are two “relatively narrow” categories of “regulatory action that generally will be deemed *per se* takings for Fifth Amendment purposes.” *Lingle*, 544 U.S. at 538. GP faintly suggested that under certain circumstances the TRM could result in the second category of *per se* taking, “because it would deprive Georgia-Pacific of all of the economically beneficial use of its CF/CT designation.” GP Brief, TRM-12-B-GP-01, at 15 n. 33. This notion is untenable because, just like the rest of GP’s takings theory, it is premised only on the “property right” that GP has in its contract with Clatskanie. As discussed above, this is not a legally cognizable property interest that has suffered a taking as a result of the TRM. In addition, this category of *per se* taking is not available because GP is not claiming a complete loss of “all” of the economically beneficial use of its contract, only that the contract would be *less* economically beneficial.

Third, the connection between BPA's TRM and the price GP may ultimately pay for power from Clatskanie is too attenuated to establish an economic impact. BPA will sell power to Clatskanie at wholesale rates; Clatskanie in turn sets its own retail rates for selling power to its customers such as GP. Clatskanie Official Statement, at 12. BPA is not involved in Clatskanie's process of setting retail rates and has no control over the rate Clatskanie may ultimately charge to GP. *Id.* Indeed, the record shows that, if anything, Clatskanie's rates are exceedingly low. Stene, *et al.*, TRM-12-E-BPA-18, at 8, and Attachment A. Because Clatskanie PUD has such low rates, GP's suggestion of economic impact is rendered even more speculative.

2. Interference with investment-backed expectations

This factor "incorporates an objective test—to support a claim for a regulatory taking, an investment-backed expectation must be 'reasonable.'" *Cienega Gardens*, 331 F.3d at 1346 (quoting *Ruckelshaus v. Monsanto Co.*, 467 U.S. 986, 1005 (1984)). This factor most directly demonstrates the failings of GP's takings argument: GP's investment-backed expectation is not reasonable.

GP states that it "has invested more than \$450 million in two new machines at the Wauna facility..." and this investment was made "in reliance on the continued availability of low rates for CF/CT loads." GP Brief, TRM-12-B-GP-01, at 17. GP has an incorrect understanding of CF/CT status.

First, GP has no direct right under section 3(13) of the Northwest Power Act to buy power at the PF rate. 16 U.S.C. § 839a(13). BPA sells power only to the local serving utility, in this case Clatskanie. In turn, Clatskanie will determine its retail rate design and set the price for GP's service. This has always been the relationship between BPA and Clatskanie and between Clatskanie and GP. Accordingly, it is not reasonable for GP to expect that it is entitled to dictate which PF rate with which BPA serves Clatskanie.

Second, CF/CT does not encompass a right to the "lowest preference rate," as GP claims. GP Brief, TRM-12-B-GP-01, at 17-18. The CF/CT designation merely allows the BPA customer that serves CF/CT loads to include such load as part of its load that is served with general requirements power sold at the applicable PF rate established under section 7(b) of the Northwest Power Act. CF/CT status certainly does not bestow a right to the "lowest" PF rate. No such right exists for *any* customer of BPA's, much less for a retail consumer such as GP to whom BPA owes no statutory or contractual duties. *See Central Lincoln People's Util. Dist. v. Johnson*, 735 F.2d 1101, 1125 (9th Cir. 1984) (as amended on denial of rehearing and rehearing *en banc*) (stating that the Northwest Power Act "couches the preference in terms of 'power sales,' not price."); *Trinity County Pub. Util. Dist. v. Harrington*, 781 F.2d 163, 166 (9th Cir. 1986) (allocation does not result in "a preferential rate in addition to a preferential power allocation"); *Kaiser Aluminum & Chem. Corp. v. Bonneville Power Admin.*, 261 F.3d 843, 851 (9th Cir. 2001) (regional power preference does not provide price preference). BPA's TRM does not propose to extinguish any right of a serving utility (such as Clatskanie) to have BPA serve its CF/CT load at PF rates. Stene, *et al.*, TRM-12-E-BPA-18, at 7. However, that is the extent of the rights that CF/CT status confers—it does not further convey any sort of right to the "lowest" rate.

Third, GP avers that it had “no indication that the CF/CT load would not continue to be entitled to all of the historical rights of CF/CT to the lowest preference rate” and that it “could not have reasonably anticipated the possibility that BPA would promulgate a rate proposal that would severely undermine the value of its operations in the Northwest.” GP Brief, TRM-12-B-GP-01, at 17-18, 19-20. Beyond the fact that GP never had any right to the “lowest” preference rate to begin with, the suggestion that GP was not aware of the possibility that BPA could tier rates is without merit. BPA has asserted its authority to tier rates for many years. *See, e.g.*, Notice of Proposed Wholesale Power Rate Adjustment, 60 Fed. Reg. 8496 (Feb. 14, 1995), at 8497-98, 8503-04. Similarly, in BPA’s applicable wholesale firm power rates for the period FY 2001 through FY 2006, and current effective rates, BPA established a Targeted Adjustment Charge (TAC) that applies to customer load that had not been forecast to be served within the rate period. The TAC is designed to recover any incremental costs BPA incurs to acquire power that is needed to sell power to its customer to supply such unexpected load. 2002 Wholesale Power Rate Schedules at 136 (September 2001); 2007 Wholesale Power Rate Schedules at 118 (November 2006); and 2007 Supplemental Wholesale Power Schedules (FY 2009) (the latter two have received interim Commission approval). BPA has had the authority to tier rates since at least the passage of the Northwest Power Act. *See* Issues 2 and 3 *supra* for further discussion. Thus, to the extent GP relied on the absence of a tiered rates structure in making its investments at Wauna, such reliance was not reasonable.

3. Character of the government action

In analyzing this factor, a court would consider whether the government action “amounts to a physical invasion or instead merely affects property interests through ‘some public program adjusting the benefits and burdens of economic life to promote the common good.’” *Lingle*, 544 U.S. at 539 (*quoting Penn Central*, 438 U.S. at 124). Where the “interference with the property rights ... arises from a public program that adjusts the benefits and burdens of economic life to promote the common good” then the action “does not constitute a taking requiring Government compensation.” *Connolly v. Pension Benefit Guaranty Corp.*, 475 U.S. 211, 225 (1986) (collecting cases).

GP contends that BPA has “not shown that any public interest is served by its proposal” GP Brief, TRM-12-B-GP-01, at 18. Quite the contrary; the TRM embodies the quintessential non-taking public purpose, namely, it is about “adjusting the benefits and burdens of economic life to promote the common good” *Connolly*, 475 U.S. at 225. BPA has explained, *ad nauseam*, the public purposes behind tiering rates in general and how the TRM advances these goals. *See* RD Policy, at 5-7, 21-23; *Cherry et al.*, TRM-12-E-BPA-02, at 2-4; 73 Fed. Reg. 24961-64 (May 6, 2008). With specific regard to treatment of CF/CT load under a tiered rates construct, GP is incorrect that BPA has not explained its rationale. *See* GP Brief, TRM-12-B-GP-01, at 18. The RD Policy ROD, which Staff summarized in testimony, evaluated this issue and thoroughly explained BPA’s actions. *See* *Stene et al.*, TRM-12-E-BPA-18, at 2-3.

IV. The remedy GP is seeking is not available under the law of takings.

GP's basic argument is that "the TRM will constitute a regulatory taking of GP's property interests under its contract with Clatskanie, for which GP must be compensated." GP Brief, TRM-12-B-GP-01, at 15. Yet, in each instance that GP alleges it "is entitled to just compensation" it fails to state what that compensation would be. *Id.* at 11, 12, 14, 15, 19. Nowhere in GP's testimony or briefing does it present an amount of compensation to which it believes it is entitled.

The obvious reason for this missing element is that GP cannot show with any certainty what amount, if any, the TRM will "take" from it. This is because, as discussed above, any attempt at showing GP's potential "derivative" losses would be purely speculative.

In reality, GP is attempting to stop BPA from tiering rates altogether—much of GP's brief is devoted to arguing that the tiered rate proposal "exceeds BPA's statutory authority and is contrary to law." GP Brief, TRM-12-B-GP-01, at 8, 3-11. Thus, what GP is seeking amounts to an injunction against the passage and implementation of the TRM. The Supreme Court has held that such a claim "does not sound under the Takings Clause." *Lingle*, 544 U.S. at 544. This is because the party "plainly does not seek compensation for a taking of its property for a legitimate public use, but rather an injunction against the enforcement of a regulation... ." *Id.* Accordingly, the relief GP seeks is fundamentally at odds with the "just compensation" available under the Takings Clause. Therefore, GP's takings argument is invalid.

V. Conclusion

GP's takings argument is invalid for several independent reasons. GP does not have a legally cognizable property interest that has suffered a taking as a result of the TRM, its alleged loss is merely consequential and not one for which takings law affords a remedy, it fails the *Penn Central* standards for establishing a regulatory taking, and the remedy it is seeking is not available under the law of takings.

Decision

The TRM does not result in an unconstitutional taking of property from Georgia-Pacific.

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3.0 The Tiered Rate Methodology

3.1 Cost Allocations

3.1.1 Rate Directives

The TRM establishes a methodology that provides for a two-tiered Priority Firm Power (PF) rate design applicable to firm requirements power service for Publics pursuant to CHWM Contracts. The tiered rate design differentiates between the costs of service associated with Tier 1 System Capability (Tier 1 Rates) and the costs associated with amounts of BPA power needed to serve any portion of a Public's Annual Net Requirement not served at a Tier 1 Rate (Tier 2 Rates). The TRM specifies how PF rates will be developed by BPA to ensure, to the maximum extent possible, that Tier 1 Rates do not include costs of serving Publics' Above-RHWM Load.

Section 7 of the Northwest Power Act contains a number of directives that BPA must observe in setting its rates for the sale of power. Among these rate directives, sections 7(b)(1), 7(b)(2), and 7(g) govern the determination of the costs included in the PF Preference rate.

The TRM is not intended to supersede any section 7 rate directives. Some parties have raised issues regarding the relationships between the section 7 rate directives and the TRM.

Issue 1

Whether the TRM complies with the section 7 rate directives.

Parties' Positions

The PPG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, Cowlitz PUD, Grays Harbor PUD, and ICNU, notes that the TRM cannot override or conflict with the rate directives in section 7 of the Northwest Power Act. PPG Brief, TRM-12-B-PPG-01, at 2; Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook PUD, TRM-12-M-CL-01; Canby Joinder, TRM-12-M-CA-01; Cowlitz Joinder, TRM-12-M-CO-01; Grays Harbor Joinder, TRM-12-M-GH-01; ICNU Joinder, TRM-12-M-IN-03. The PPG concludes that the resource costs included in the revenue requirement allocated to the tiered PF Preference rates must be established consistent with, and limited as required by, the section 7 rate directives independent of any tiering of the PF Preference rates. PPG Brief, TRM-12-B-PPG-01, at 2.

WPAG, joined by Clatskanie PUD, Canby Utility Board, and GP, notes that the Northwest Power Act contains express resource cost allocations that BPA must follow in constructing the rates charged to preference customers. WPAG Brief, TRM-12-B-WA-01, at 4; Clatskanie Joinder, TRM-12-M-CK-02; Canby Joinder, TRM-12-M-CA-01; GP Joinder, TRM-12-M-GP-05. WPAG's argument is addressed in section 2.0, Issue 2, *supra*.

BPA Staff's Position

BPA Staff agrees that there needs to be a better distinction between the allocation of costs, as described in the TRM, and how BPA's statutory rate directives will be implemented through the TRM. Cherry *et al.*, TRM-12-E-BPA-15, at 12. Staff proposed a series of workshops to ensure that BPA allocates costs consistent with BPA's rate directives under the Northwest Power Act and this TRM and to provide an understanding of how BPA will implement tiered rates under these rate directives. *Id.*

Evaluation of Positions

BPA agrees with the PPG and WPAG that the section 7 rate directives must be followed in implementing tiered rates. BPA does not believe that there is any provision of the TRM that contradicts or supersedes the rate directives. Ultimately, the proof will be in the actual implementation of the TRM in the ratesetting process. Once the implementation is complete, BPA will address any specific concerns of any rate case party regarding the interrelationships between the rate directives and the tiering of the preference customer rate.

The PPG points out that the TRM, while purporting to deal exclusively with the design of the PF Preference rates applicable to purchases under CHWM Contracts, describes in a number of places how BPA's total power costs (or elements of BPA's power costs that are not to be recovered solely through PF Preference rates) will be treated. PPG Brief, TRM-12-B-PPG-01, at 2. The PPG urges BPA to include new TRM language to resolve the conceptual confusion resulting from the mixture of TRM discussions concerning BPA power costs generally and discussions dealing with costs to be recovered through tiered PF Preference rates specifically. *Id.* at 2-3. The PPG proposes specific language to be included in the TRM. *Id.* at 3. This language, with additional revisions, is shown below.

BPA understands the PPG's concern that the TRM was not as clear as it could be regarding the inclusion of all costs and the resulting allocation of the costs to the different rate classes. The PPG proposed language is acceptable to BPA as an attempt to resolve some of the confusion. Although it is an improvement, the PPG's proposed language does not resolve all the confusion. The source of the confusion may stem from the use of a single term for multiple purposes. The TRM identified the Cost Allocation Table as both the accumulation of all of BPA's costs prior to allocations to the different rate classes and as the table stating the costs allocated to preference customers and used to calculate the tiered preference rates. This confusion can be lessened if different terms are adopted for these distinct purposes.

Therefore, to reduce some of this confusion, the TRM will be modified to replace the term "Cost Allocation Table" with two new terms: "Revenue Requirement Table" and "Allocated Tiered Cost Table." The term "Revenue Requirement Table" will be used when referring to the accumulated costs prior to allocation. The term "Allocated Tiered Cost Table" will be used when referring to the table of costs allocated to preference customer rates. The language proposed by the PPG will be incorporated into sections 1.2 and 2.2 of the TRM, as modified herein:

1.2 Scope of TRM References and Descriptions

In general, the provisions of the TRM are limited to the design and implementation of the PF tiered rates. This is not universally the case, however. Throughout the TRM, there are references to BPA's power costs in aggregate, or to elements of BPA's power costs that are not recovered solely through the PF Preference [r]ates. ~~For example, in section 2.2, [T]he TRM states that all costs BPA functionalizes to power will be included in the Cost Allocation Revenue Requirement Table. See section 2.2. , even though most references to the Cost Allocation Table, or to [T]he Cost Pools into which all entries in the Cost Allocation on the Allocated Tiered Cost Table, Table 2, into which all line items on the Revenue Requirement Table are divided (allocated), address treatment of costs to be recovered either through Tier 1 Rates or Tier 2 Rates. These Cost Pools on the Allocated Tiered Cost Table do not address (and not BPA power costs on the Revenue Requirement Table that are to be recovered through (allocated to) other rates, such as the ~~PF Exchange rate~~, the NR rate, or the IP rate).~~

To the extent the TRM makes reference to costs that reach beyond those to be recovered through tiered PF rates, this is not intended to imply that Publics purchasing requirements power from BPA at tiered rates will be responsible for these costs. Rather, these statements should be understood in the context of the sequential process through which BPA will first determine its power costs, and the portions of BPA's power costs to be allocated to the applicable customer rate classes, all in accordance with the rate directives of section 7 of the Northwest Power Act, and then apply the provisions of the TRM to tier the portions of its total power costs to be recovered through its PF Preference Rates.

Except as described above and in section 10.5, the TRM does not address issues relating to other BPA rates, ~~including but not limited to the PF rate applicable to customers that do not sign CHWM Contracts~~. Power products are determined in CHWM contracts, not in this TRM.

* * * *

2.2 Cost Allocation Method and ~~Cost Allocation~~ Allocated Tiered Cost Table

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

The ~~Cost Allocation~~ Allocated Tiered Cost Table, Table 2, sets out the cost allocations categories that will be used for allocating costs in future

7(i) Processes. Any changes to the ~~Cost Allocation~~ Allocated Tiered Cost Table to accommodate New Expenses or New Credits will be pursuant to section 2.3. Any changes to the ~~Cost Allocation~~ Allocated Tiered Cost Table to accommodate a need to allocate a Tier 2 Cost to a Tier 1 Cost Pool will be pursuant to section 2.6. All other changes to the ~~Cost Allocation~~ Allocated Tiered Cost Table will be pursuant to sections 12 and 13. All BPA costs functionalized by BPA to power will be included in the ~~Cost Allocation~~ Revenue Requirement Table, but ~~Tier 1 Rates and Tier 2 Rates~~ the Allocated Tiered Cost Table will reflect only those portions of BPA's total power costs that, in accordance with section 7 of the Northwest Power Act and the TRM, are to be recovered from Publics that have executed CHWM Contracts. The addition of new Tier 2 Cost Pools will not be considered changes to the ~~Cost Allocation~~ Allocated Tiered Cost Table for purposes of sections 12 and 13.

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

2.2.1 The Composite Cost Pool

~~Table 2~~, Section B of the Allocated Tiered Cost Table sets out the categories of costs that are allocated to the Composite Cost Pool, including all Tier 1 Costs and Tier 1 Credits functionalized by BPA to power, except for any Tier 1 Costs or Tier 1 Credits that BPA has determined meet the specified criteria for inclusion in either the Slice Cost Pool or the Non-Slice Cost Pool, as set forth in sections 2.2.2 and 2.2.3. The administrative costs (primarily staffing costs) of surplus marketing and administering all CHWM Contracts and rates will be allocated to the Composite Cost Pool. Allocation of costs between the Composite Cost Pool and Non-Slice Cost Pool is shown on Table 2, Section A, with the resulting allocation reflected in the relevant Cost Pools, sections B and D.

2.2.2 The Slice Cost Pool

~~Table 2~~, Section C of the Allocated Tiered Cost Table is designed to include the costs that are allocated to the Slice Cost Pool, including all Tier 1 Costs and Tier 1 Credits that are specifically and uniquely attributable to the Slice product. As of the date of this TRM, there are no Tier 1 Costs or Tier 1 Credits to be allocated to the Slice Cost Pool. If, during the term of the Slice/Block CHWM Contracts, BPA undertakes actions that are solely for the benefit of the Slice customers (for example, customer-requested software enhancements specific to

Slice), then BPA will allocate the costs of undertaking these actions to the Slice Cost Pool unless BPA and the Slice customers have made separate payment arrangements. Such costs would be treated as New Expenses under the TRM for allocation purposes. Similarly, if in the future there are New Credits attributable to the Slice customers only, these New Credits would be allocated to the Slice Cost Pool.

2.2.3 The Non-Slice Cost Pool

Table 2, Section D of the Allocated Tiered Cost Table sets out the categories of costs that are allocated to the Non-Slice Cost Pool, including all Tier 1 Costs and Tier 1 Credits that are specifically and uniquely attributable to the Load Following or Block products, including the Block portion of the Slice/Block product. The Non-Slice Cost Pool includes the costs and credits of converting resource output into load service (e.g., Balancing Power Purchases); the costs of Tier 1 risk mitigation not recovered through rates for the Slice product; and the costs or credits arising from capacity resource purchases. The Non-Slice Cost Pool also includes the Tier 1 Secondary Energy Credit, which includes any costs or credits specifically attributable to BPA's marketing of Tier 1 Secondary Energy.

2.2.4 Tier 2 Cost Pools

Table 2, Section E of the Allocated Tiered Cost Table sets out the costs that are allocated to the Tier 2 Cost Pools. Such costs include all Tier 2 Costs that are attributable to resources and services that BPA forecasts for ratemaking purposes to use for serving load at a Tier 2 Rate. Included in Table 2, Section E, are RSS costs used to set the Tier 2 Rates. BPA will include a uniform adder, the Overhead Cost Adder, in the Tier 2 Cost Pools. BPA will credit the forecast revenue from the Overhead Cost Adder to the Composite Cost Pool. See section 6.3 for a fuller discussion of costs allocated to Tier 2 Cost Pools and section 6.3.3 for discussion of the Overhead Cost Adder. Any uses of the Tier 1 System to serve load at a Tier 2 Rate, as forecast for ratemaking purposes, will be priced in accordance with section 3.7.

Further changes to the TRM to incorporate this clarification will be made in the definitions and text. The Cost Allocation Table defined term will be replaced with two new defined terms:

Allocated Tiered Cost Table means the table that sets forth the expenses and revenue credits allocated to the Publics in the Cost Pools that result from application of the Cost Allocation Method.

Revenue Requirement Table means the table that sets forth expenses and revenue credits that BPA will use when implementing the Cost Allocation Method. The line items on the Revenue Requirement Table are similar to those on the Allocated Tiered Cost Table, but without the Cost Pool distinctions.

References in TRM sections 2.7.3 and 12.5 will be changed from Cost Allocation Table to Allocated Tiered Cost Table. To further clarify the distinction between the tables, the sections referring to the rates applicable to preference customers will include a reference to the Allocated Tiered Cost Table to designate that rates will not be determined using the Revenue Requirement Table, as shown below.

5.1.3 Composite Customer Rate

BPA will charge the Composite Customer Rate to all Publics that sign a CHWM Contract. The Composite Customer Rate will recover all costs BPA allocates to the PF Preference Rate from the Composite Cost Pool (as delineated on the Allocated Tiered Cost Table) and will be expressed in dollars per one percentage point of TOCA. See Table 2, Section B, for a listing of specific cost items in the Composite Customer Rate. The Composite Customer Rate will not change even if BPA adjusts any customer's TOCA during a particular Rate Period.

5.1.4 Non-Slice Customer Rate

BPA will charge the Non-Slice Customer Rate only to customers purchasing Load Following and Block Products. The Non-Slice Customer Rate will collect all costs allocated to PF Preference Rates from the Non-Slice Cost Pool (as delineated on the Allocated Tiered Cost Table). See Table 2, Section D, for a listing of specific items in the Non-Slice Cost Pool. The Non-Slice Customer Rate will be expressed in dollars per one percentage point of Non-Slice TOCA. The Non-Slice Customer Rate will not change even if BPA adjusts any customer's TOCA during a particular Rate Period.

5.1.5 Slice Customer Rate

BPA will charge the Slice Customer Rate only to customers purchasing the Slice portion of the Slice/Block product. The Slice Customer Rate will collect all costs allocated to the Slice Cost Pool. See Table 2, Section C, for a listing of specific items in the Slice Cost Pool (as delineated on the Allocated Tiered Cost Table). The Slice Customer Rate will be expressed in dollars per one percentage point of Slice Percentage. The Billing Determinant will be the customer's contractually specified Slice Percentage. The Slice Customer Rate will not change even if BPA adjusts any customer's Slice Percentage during a particular Rate Period.

Decision

The intent of the TRM is to implement tiered rates in a manner entirely consistent with, and subservient to, the section 7 rate directives. BPA does not currently see any provision in the TRM that is in conflict with the section 7 rate directives. If, during the implementation of the TRM, BPA and parties agree that a provision of the TRM is in conflict with the section 7 rate directives, BPA will work with parties to the TRM rate case to resolve such conflict and revise the TRM under the unintended consequences provisions of the TRM. If BPA does not agree that a provision is in conflict, but a court directs that a provision is in conflict, sections 12 and 13 of the TRM preserve BPA's full authority to modify the TRM to respond to court order.

Issue 2

Whether the TRM results in charging preference customers market prices in violation of the section 7 rate directives.

Parties' Positions

WPAG, joined by Clatskanie PUD, Canby Utility Board, and GP, argues that charging preference customers market prices for energy and capacity supplied by the FBS, as envisioned by the TRM, is inconsistent with the limitation on the “amounts charged” preference customers as established in section 7(b)(2) of the Northwest Power Act. WPAG Brief, TRM-12-B-WA-01, at 5; Clatskanie Joinder, TRM-12-M-CK-02; Canby Joinder, TRM-12-M-CA-01; GP Joinder, TRM-12-M-GP-05.

BPA Staff's Position

This issue was first raised on brief. BPA Staff did not submit a statement of its position on this issue.

Evaluation of Positions

The TRM will not result in market prices for energy and capacity, as WPAG claims. To the contrary, the TRM will produce PF rates that are cost based and, consistent with BPA's historical rate design practices, include design components that send appropriate pricing signals. *Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 1122 (9th Cir. 1984) (*Central Lincoln II*), citing 126 Cong.Rec. H10, 526-27 (daily ed. Nov. 12, 1980), reprinted in BPA Legislative History at 171-72. Since the Northwest Power Act was enacted, BPA has set PF rates to recover only its embedded cost while including rate design elements that provide information about the relative costs of energy and capacity. For example, BPA's PF rate that went into effect July 1981 was based on the Long Run Incremental Cost Analysis, which is a method of applying the principles of marginal cost pricing to electric rates. The current PF energy rates are shaped to reflect forecast market prices in heavy load hours (HLH) and light load hours (LLH) for each month. Such rate design provides information to customers, enabling them to make informed consumption decisions to make efficient use of power and to make resource decisions. While certain of the rate components of the tiered rate design may rely on market prices in the determination of the rate level, BPA will fully comply with the instructions of sections 7(b) and 7(g) regarding the amounts charged to preference customers being in accord with the rate directives. The rates determined under the TRM will be set in such a way that the amounts charged to preference customers will be limited by section 7(b)(2), if such limitation is necessary as demonstrated in each relevant 7(i) Process. BPA's PF rates will, in total, recover no more than BPA's costs. In doing so, they will, in accordance with section 7(e), provide marginal price signals, consistent with the congressional understanding that the individual rate pool directives concern the amount of money to be recovered from each rate class, not the form of recovery.

Decision

The TRM does not result in the “amounts charged” to preference customers being determined by market prices for energy and capacity. The TRM comports with the section 7 rate directives.

Issue 3

Whether BPA should make its new rate model available for review prior to the first 7(i) Process in which it will be used.

Parties’ Positions

The PPG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, Cowlitz PUD, Grays Harbor PUD, and ICNU, states that customers must not be exposed to BPA’s new rate model for the first time during the formal stage of the first rate case in which that model will be used. PPG Brief, TRM-12-B-PPG-01, at 5; Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; Canby Joinder, TRM-12-M-CA-01; Cowlitz Joinder, TRM-12-M-CO-01; Grays Harbor Joinder, TRM-12-M-GH-01; ICNU Joinder, TRM-12-M-IN-03. The PPG requests that BPA share the model in advance of the FY 2012 rate case so that customers can thoroughly explore and understand the model and gain confidence that the model faithfully and correctly carries out the section 7 rate directives and the explicit arrangements negotiated in the TRM. PPG Brief, TRM-12-B-PPG-01, at 5.

BPA Staff’s Position

BPA Staff did not address this issue in testimony. In settlement discussions during the section 7(i) proceeding, Staff agreed that parties should have opportunity to review and test the model in advance of its use in a 7(i) Process.

Evaluation of Positions

The PPG proposes revised TRM language that would commit BPA to revise and release a modified rate model by September 2009 and conduct workshops for customers to review and understand the modeling.

BPA shares the PPG’s concerns that the modeling of tiered rates conform both to the section 7 rate directives and the TRM. It is not enough for BPA to state in the TRM how it intends to tier rates to preference customers. The true measure of BPA’s actions will be in the rate modeling, through which BPA will establish whether the tiering of rates conforms to both the section 7 rate directives and the provisions of the TRM.

BPA recognizes that, as complex as the process of setting power rates in accordance with section 7 of the Northwest Power Act has proven to be without tiered rates, the tiering of PF

Preference Rates for FY 2012 and beyond will add even greater complexity. BPA believes all parties will benefit from early development and testing of the rate models to be used in setting tiered rates—well before the start of the 7(i) Process to establish FY 2012 rates. BPA has already initiated its tiered rates model development process but believes that releasing the model by September 2009 as the PPG requested is too optimistic. The WP-10 and TR-10 rate proceedings likely will require significant time for both Staff and rate case parties. BPA is willing to commit to make available to all interested parties, by March 2010, electronic copies of a rate model that implements the TRM. BPA also will make available documentation explaining what each new module of the model does and how the modules relate to and implement the rate directives of section 7 and the tiering of the costs applicable to the PF Preference Rates. After the model is released, BPA will convene a series of workshops to explain and answer questions about the rate model and to allow all interested parties to provide feedback about the model and associated documentation.

BPA does not believe that the PPG's proposed language regarding this subject needs to be included in the TRM. Such language regards a one-time event in advance of the actual tiering of rates and is not necessary for future implementation of the TRM. However, BPA is willing to adopt the PPG's proposed language, with some revisions, as the decision in this ROD. In incorporating the PPG's proposed language as a decision in this ROD, BPA believes that it carries the same weight and force as if the language were to be included in the TRM. However, BPA cannot agree that the model released in March 2010 will be identical to the model used for the WP-12 initial proposal. Any number of model components may need to change in preparing an initial proposal.

Decision

BPA will make its new rate model available for review prior to the first 7(i) Process in which it will be used. By March 2010, BPA will make available electronic copies of the rate model that implements the TRM. BPA also will make available documentation for new procedures added to the model. After the model is released, BPA will convene a series of workshops to explain and answer questions about the rate model and to receive feedback about the model and its documentation.

3.1.2 Secondary Revenue Credit

Issue 1

Whether addressing the treatment of the secondary revenue credit in the TRM is appropriate in specifying that all secondary revenues will be credited against the costs of resources that produce the secondary energy and whether the TRM should make clear that the secondary energy credit allocated to the Non-Slice Cost Pool is to be the equivalent of the advance sale of surplus energy under the Slice Product.

Parties' Positions

The PPG and WPAG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, Cowlitz PUD, Grays Harbor PUD, and ICNU, proposed additional language for the TRM that addresses the use of secondary revenues in BPA's ratemaking. PPG Brief, TRM-12-B-PPG-01, at 10; WPAG Brief, TRM-12-B-WA-01, at 16; Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; Canby Joinder, TRM-12-M-CA-01; Cowlitz Joinder, TRM-12-M-CO-01; Grays Harbor Joinder, TRM-12-M-GH-01; ICNU Joinder, TRM-12-M-IN-03. The PPG and WPAG proposed two new principles to be included in section 2.1 of the TRM:

- 8) All forecast revenues from the sale by BPA of secondary energy produced by FBS and new resources will be, for rate making purposes, applied as an offset to costs that are properly allocable to rates for BPA sales of power for use within the region.
- 9) Costs or benefits associated with the sales of or inability to sell excess power allocated under section 7(g) of the Northwest Power Act will be allocated to the Cost Pools to which the costs of the resources generating such excess power are allocated.

PPG Brief, TRM-12-B-PPG-01, at 10; WPAG Brief, TRM-12-B-WA-01, at 16.

Next, the PPG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, Cowlitz PUD, and Grays Harbor PUD, and WPAG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, and ICNU, proposed additional language regarding the treatment of secondary revenues in the Non-Slice Cost Pool to be analogous to the secondary energy delivery to Slice customers. PPG Brief, TRM-12-B-PPG-01, at 11; WPAG Brief, TRM-12-B-WA-01, at 16; Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; Canby Joinder, TRM-12-M-CA-01; Cowlitz Joinder, TRM-12-M-CO-01; Grays Harbor Joinder, TRM-12-M-GH-01; ICNU Joinder, TRM-12-M-IN-03. This language was proposed to be included in section 2.4 of the TRM:

The Slice Product includes an advance sale of surplus energy, which is delivered when and if available. As a consequence, the Composite Cost Pool and Slice Cost Pools do not contain any revenue cost or credit associated with ~~the~~ Tier 1 Secondary Energy Credit. The Load Following and Block Products do not receive any Tier 1 Secondary Energy. Therefore, the Non-Slice Cost Pool will be allocated a Tier 1 Secondary Energy Credit equivalent to the advance sale of surplus power included as part of the Slice Product.

PPG Brief, TRM-12-B-PPG-01, at 11; WPAG Brief, TRM-12-B-WA-01, at 16.

The IOUs responded to testimony presented by Clark, the PPG, and WPAG regarding the treatment of the secondary revenue credit, which included the language cited above. The IOUs noted that the aforementioned publics filed testimony that advocated that the TRM address crediting of revenues from BPA's sale of secondary energy as an offset to the costs of the associated resources, and that it indicate or suggest that BPA's forecast secondary revenues should serve as a credit against FBS resource costs. IOU Brief, TRM-12-B-JP-01, at 17. The IOUs expressed concern that such testimony is not limited to addressing allocation of PF Preference rate costs (or credits) between Tier 1 and Tier 2, but rather addresses the revenue credit to be made in setting rates under the TRM. *Id.* The IOUs stated that such language is inappropriate for the TRM. *Id.*

BPA Staff's Position

BPA Staff strove to strike a balance between the publics' concern that the TRM express some certainty regarding the treatment of secondary revenues in the development of the tiered PF Preference rate and the IOUs' concern that the TRM not stray beyond its scope of addressing items solely limited to the tiering of the PF Preference rate. Staff engaged in settlement discussions with parties to seek language that could strike that balance.

Staff and parties agreed to modify the PPG and WPAG proposal into one new principle to be proposed for section 2.1, as follows:

- 8) As a consequence of the customers' contractual take-or-pay obligation to pay for power at rates established by BPA pursuant to Northwest Power Act section 7 to recover, in accordance with sound business principles, BPA's costs of acquiring, conserving, and transmitting electric power, including amortization of the Federal investment in the Federal Columbia River Power System over a reasonable number of years, and all other costs and expenses incurred by the Administrator pursuant to law, and for so long as customers continue to fulfill their contractual take-or-pay obligations, then:
 - (1) all revenues forecast by BPA from its sale of secondary energy produced by Federal Base System and other resources acquired by the Administrator will continue to be credited by BPA in the ratemaking process pursuant to Northwest Power Act section 7(g) against costs that are properly allocated to rates for recovery from sales of power for use within the region; and
 - (2) costs and benefits of the sale of or inability to sell excess electric power allocated under section 7(g) of the Northwest Power Act will be allocated to the Cost Pools to which the costs of the resources that generate such excess electric power are allocated.

BPA Motion, TRM-12-M-BPA-11, Attachment A. Staff and parties also agreed to modify the PPG and WPAG proposal for section 2.4, as follows:

2.4 Tier 1 Secondary Energy Credit

The Slice Product includes an advance sale of surplus energy, which is delivered when and if available. As a consequence, the Composite Cost Pool and Slice Cost Pool do not contain any cost or credit associated with Tier 1 Secondary Energy.

The Load Following and Block Products do not receive any Tier 1 Secondary Energy. Therefore, the Non-Slice Cost Pool will be allocated a Tier 1 Secondary Energy Credit. Notwithstanding any other provision in this TRM, and irrespective of whether BPA allocates section 7(b)(2) trigger amounts to BPA surplus sales, BPA will seek to ensure comparable treatment with respect to Tier 1 Secondary Energy as between the Slice and Non-Slice Cost Pools.

Id.

Evaluation of Positions

As a result of settlement discussions on September 30, 2008, Staff proposed modifications to TRM sections 2.1 and 2.4. TRM-12-M-BPA-11, Attachment A. The PPG and WPAG agreed that BPA's proposal would resolve their issues. PPG Motion, TRM-12-M-PPG-04, at 7-8; WPAG Motion, TRM-12-M-WA-02, at 1-2. Thus, all those joining with the PPG and WPAG are deemed to have issues resolved. The IOUs did not indicate the proposed language resolved their issues.

While the IOUs are correct that the treatment of BPA's forecast secondary revenues as an offset to the costs of the associated resources is an issue to be undertaken in the relevant 7(i) Processes conducted under the TRM, BPA notes that the treatment memorialized in the settlement language has been in use for many years in BPA's ratesetting methodology. The IOUs are possibly reflecting on statements made during settlement discussions that attempted to characterize the secondary revenue credit being assigned to one rate class or another. Such characterizations may have been actual misstatements or simply shorthand references to BPA's actual practices. However, it has been BPA's practice for years to credit forecast secondary revenue against the costs of specific resource pools.

The TRM presents one nuance that may be a change in BPA's past practices of crediting secondary revenues against resource pool costs. The final TRM states that "...costs and benefits of the sale of or inability to sell excess electric power allocated under section 7(g) of the Northwest Power Act will be allocated to the Cost Pools to which the costs of the resources that generate such excess electric power are allocated."

In the past, BPA has credited secondary revenues against the costs of the Federal system resources—that is, the costs of resources in the FBS and new resources resource pools. BPA reads the TRM language cited immediately above to restrict the secondary revenues produced by FBS resources to be an offset of FBS costs and the secondary revenues produced by new resources, if any, to be an offset of new resources costs. At this time, BPA does not believe that this language constitutes or should result in a change in the construction of the PF Exchange rate. That rate has historically benefited from the allocation of secondary revenues and this language does not affect that historic practice. If anything, the language should benefit the IOU and public exchanging utilities by focusing the secondary revenue credit on the FBS. The PF Exchange rate has access to the FBS equal to that of the PF Preference rate. *See* section 7(b)(1) of the Northwest Power Act, 16 U.S.C. § 838e(b)(1). As noted in the TRM, "All issues pertaining to

calculation of the section 7(b)(2) rate test and allocation of the section 7(b)(3) surcharge will be determined in the applicable 7(i) Process.” TRM-12-E-BPA-20 at 98.

Decision

BPA adopts the proposed settlement modifications to TRM sections 2.1 and 2.4. The adoption of this language is necessary to clarify the treatment of the secondary revenue credit in the tiering of the PF Preference rate. The TRM language does not implicate the treatment of the secondary revenue credit in the determination of the PF Exchange or any other rate. BPA does not believe that the TRM language constitutes or should result in a change in the construction of the PF Exchange rates applying to both IOU and public utilities, including a change that would reduce the extent to which the PF Exchange rates benefit from an allocation of secondary revenue.

3.2 Federal System Resources

3.2.1 Critical Period Definition

Issue 1

Whether to adopt the definition of “Critical Period” set forth in Attachment A to BPA’s Motion to Supplement the Record and Allow for Comment.

Parties’ Positions

The PPG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, Cowlitz PUD, and Grays Harbor PUD, stated that the TRM definition of Critical Period that Staff proposed in rebuttal testimony, if combined with another PPG proposed change, may provide adequate certainty regarding the method through which BPA will determine the Critical Period and Firm Critical Output of Tier 1 System Resources. PPG Brief, TRM-12-B-PPG-01, at 20; Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; Canby Joinder, TRM-12-M-CA-01; Cowlitz Joinder, TRM-12-M-CO-01; Grays Harbor Joinder, TRM-12-M-GH-01.

BPA Staff’s Position

The Critical Period definition presented in BPA Staff’s rebuttal, TRM-12-E-BPA-20, based on discussions with parties in settlement conferences up to that time, clarified BPA’s method for determining the Firm Critical Output of Tier 1 System Resources. After rebuttal was filed, Staff and parties met in additional settlement discussions on September 12 and September 30, 2008. BPA’s Motion to Supplement the Record and Allow for Comment memorialized those discussions by revising the Critical Period definition as follows.

Critical Period means the period when the expected regulated and independent hydroelectric power generation from water available from reservoir releases plus

historical natural streamflows produces the least amount of power to meet system load requirements, while taking into account the historical streamflow record, power and non-power operating constraints, the planned operation of non-hydro resources, and expected net contract obligations. For operational purposes, the Critical Period adopted by BPA as of the effective date of this TRM is September 1936 through April 1937 water conditions. However, to align with Fiscal Years, BPA will use as the Critical Period for this TRM the historical streamflows from October 1936 through September 1937 in the determination of the Firm Critical Output of the Tier 1 System Resources, unless modified pursuant to section 3.1.3.2.

BPA Motion, TRM-12-M-BPA-11, Attachment A.

Evaluation of Positions

Staff proposed a revised Critical Period definition to take into account updates to the historical streamflow record. As new historical streamflow records become available and are incorporated in BPA hydro regulation studies, those streamflow conditions may change the length and/or water conditions associated with the Critical Period. In addition, Staff revised the Critical Period definition to clarify the difference between the Critical Period BPA has adopted for operational purposes (which is the historical streamflows from September 1936 through April 1937 water conditions), and the defined TRM Critical Period used in the determination of the Firm Critical Output of the Tier 1 System Resources (which is streamflows from October 1936 through September 1937).

The PPG listed the Critical Period definition as one of the portions of the PPG brief addressed by BPA's Motion that resolved the PPG's concerns as long as the Administrator adopts that language in this ROD. PPG Motion, TRM-12-M-PPG-04, at 7-8. BPA adopts that language for the final TRM and this ROD. Thus, all those joining with the PPG are deemed to have their relevant issues resolved.

Decision

BPA adopts the Critical Period definition set forth in Attachment A to BPA's Motion to Supplement the Record and Allow for Comment.

3.2.2 Determination of the Critical Period

Issue 1

Whether to adopt the language of section 3.1.3.2 set forth in Attachment A to BPA's Motion to Supplement the Record and Allow for Comment.

Parties' Positions

The PPG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, Cowlitz PUD, and Grays Harbor PUD, proposed additions to TRM section 3.1.3.2 in combination with the revision of the definition of Critical Period included in Staff's rebuttal to clarify that any revised Critical Period must be determined by BPA in good faith to be a better method than the one being used, and that the reason for revising the Critical Period is due to circumstances external to BPA. PPG Brief, TRM-12-B-PPG-01, at 20; Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; Canby Joinder, TRM-12-M-CA-01; Cowlitz Joinder, TRM-12-M-CO-01; Grays Harbor Joinder, TRM-12-M-GH-01.

BPA Staff's Position

After rebuttal was filed, Staff and parties met in additional settlement discussions. BPA's Motion to Supplement the Record and Allow for Comment memorialized those discussions by revising TRM section 3.1.3.2 as follows.

3.1.3.2 Determination of Critical Period

For operational purposes, the Critical Period adopted by BPA as of the effective date of this TRM is September 1936 through April 1937. However, to be consistent with the corresponding Fiscal Years, BPA will use as the Critical Period for this TRM the historical streamflows from October 1936 through September 1937 in the determination of the Firm Critical Output of the Tier 1 System Resources. BPA may adopt a new Critical Period after a good faith analysis indicates that updates to power and/or nonpower requirements changed the length and/or water conditions of the then-current Critical Period such that the new Critical Period would, in BPA's determination, be more reasonable than the then-current Critical Period. Examples of these requirements that may necessitate such revision include, but are not limited to, biological opinions, court orders, treaties, statutes, regulations, executive orders, changes in thermal resource operations, changes in forecast loads, extension of the historical streamflow record, and flood control. BPA may incorporate the new Critical Period that is used to forecast the available firm output of hydroelectric projects used in the determination of the Firm Critical Output of the Tier 1 System Resources. Any changes to the Critical Period will remain in effect until further revised pursuant to this section. Changes to the Critical Period are not considered to be changes to the TRM pursuant to sections 12 and 13.

TRM-12-M-BPA-11, Attachment A.

Evaluation of Positions

Staff proposed that the following areas needed clarification in section 3.1.3.2. First, as new historical streamflow records become available, those streamflows may be incorporated in BPA

hydroregulation studies and become one of the requirements that may necessitate revision of the Critical Period. Second, BPA may adopt a new Critical Period when updates to power and/or nonpower requirements change the length and/or water conditions of the then-current Critical Period such that the new Critical Period would, in BPA's determination, be more reasonable than the then-current Critical Period. Third, changes in the Critical Period will remain in effect until further revised pursuant to section 3.1.3.2. Fourth, changes to the Critical Period are not considered to be changes to the TRM pursuant to sections 12 and 13.

After BPA filed its Motion to Supplement the Record and Allow for Comment, the PPG listed the revision of TRM section 3.1.3.2 as one of the portions of the PPG brief addressed by BPA's Motion that resolved the PPG's concerns as long as the Administrator adopts that language in this ROD. PPG Motion, TRM-12-M-PPG-04, at 7-8. BPA adopts that language for the final TRM and this ROD. Thus, all those joining with the PPG are deemed to have their relevant issues resolved.

Decision

BPA adopts the language of section 3.1.3.2 set forth in Attachment A to BPA's Motion to Supplement the Record and Allow for Comment.

3.2.3 System Obligations

Issue 1

Whether BPA should adopt the parties' additional proposed language for section 3.1.4.1 and the definition of Designated BPA System Obligations that limits how BPA can add to or change Designated BPA System Obligations.

Parties' Positions

The PPG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, Cowlitz PUD, Grays Harbor PUD, and ICNU, and Snohomish, joined by Cowlitz PUD, argue that the open-ended ability of BPA to add new or different System Obligations is a serious flaw of the TRM, because nothing prevents BPA from over-committing the existing Federal system to non-preference services (e.g., obligations to provide capacity-related services), which may then require BPA to supplement the existing Federal system with higher-cost capacity to meet its CHWM Contract commitments. PPG Brief, TRM-12-B-PPG-01, at 21; Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; Canby Joinder, TRM-12-M-CA-01; Cowlitz Joinder, TRM-12-M-CO-01; Grays Harbor Joinder, TRM-12-M-GH-01; ICNU Joinder, TRM-12-M-IN-03; Snohomish Brief, TRM-12-B-SN-01 at 3. The PPG recommends that for all new services to non-preference customers, BPA should acquire a new resource to enable the service and recover the cost of the acquisition from the parties benefiting from the service. PPG Brief, TRM-12-B-PPG-01, at 21. WPAG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD,

Tillamook PUD, Canby Utility Board, and GP, argues that the TRM fails to ensure the claim of preference customers to the output of the FBS at cost and does little to halt the diversion of FBS capability for purposes other than serving preference customer requirements load. WPAG Brief, TRM-12-B-WA-01, at 6-7; Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; Canby Joinder, TRM-12-M-CA-01; GP Joinder, TRM-12-M-GP-05.

The PPG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, Cowlitz PUD, Grays Harbor PUD, and ICNU, and Snohomish, joined by Cowlitz PUD, urge that BPA adopt the construct outlined in the PPG's direct case, under which Table 3.4 would list BPA's current obligations, which BPA could replace on expiration or add to if required by law or court order. PPG Brief, TRM-12-B-PPG-01, at 23; Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; Canby Joinder, TRM-12-M-CA-01; Cowlitz Joinder, TRM-12-M-CO-01; Grays Harbor Joinder, TRM-12-M-GH-01; ICNU Joinder, TRM-12-M-IN-03; Snohomish Brief, TRM-12-B-SN-01, at 3. The PPG proposes additional language for the second paragraph of section 3.1.4.1 as follows:

Table 3.4 may be updated in a Tier 1 System Firm Critical Output study to include new Designated BPA System Obligations; provided, however, that no new Designated BPA System Obligation will be added to Table 3.4 except for those obligations that BPA is required by regulatory authority, executive order, legislation, or court order to provide from the Tier 1 System Firm Critical Output.

PPG Brief, TRM-12-B-PPG-01, at 23.

The PPG allows that if this change was not acceptable to BPA, that BPA should adopt a revised definition of Designated BPA System Obligations. Specifically, the PPG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, Cowlitz PUD, Grays Harbor PUD, and ICNU; Snohomish, joined by Cowlitz PUD; and WPAG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, and GP, argue that BPA should limit the reasons for adding to or changing the Designated BPA System Obligations that reduce the preference customers' access to power from the Tier 1 System to only those new obligations imposed upon BPA by statute or court order. PPG Brief, TRM-12-B-PPG-01, at 23; Snohomish Brief, TRM-12-B-SN-01, at 3; WPAG Brief, TRM-12-B-WA-01, at 8; Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; Canby Joinder, TRM-12-M-CA-01; GP Joinder, TRM-12-M-GP-05; Cowlitz Joinder, TRM-12-M-CO-01; Grays Harbor Joinder, TRM-12-M-GH-01; ICNU Joinder, TRM-12-M-IN-03. The parties proposed to change the definition of Designated BPA System Obligations provided by Staff following the September 12, 2008, settlement discussion as follows:

Designated BPA System Obligations means the set of obligations, (specified in Table 3.4; imposed on BPA by statutes, regulations, court order, treaties, or executive orders (whether implemented by memoranda of agreement, and contracts, or other means)) that require the generation or delivery of power, forbearance from generating power, or receipt of power, in order to support the operation of the FCRPS, including any obligations to the BPA Balancing Authority (Transmission Services).

PPG Brief, TRM-12-B-PPG-01, at 23-24.

Subsequently PPG proposes the following revision of the definitions of Designated BPA System Obligations.

Designated BPA System Obligations means ~~the set of those BPA obligations, specified in Table 3.4, imposed on BPA by statutes, regulations, court order, treaties, or executive orders, (whether implemented by memoranda of agreement, and contracts, or other means)~~ that require ~~the support of the FCRPS by generation, or delivery, or receipt of power, or forbearance from generating power, or receipt of power, in order to support the operation of the FCRPS, including any obligations to the BPA Balancing Authority (Transmission Services)~~ comply with statues, regulations, court order, treaties, or executive orders (or memoranda of agreements, contracts, or settlements arising from the foregoing). Designated BPA System obligations do not include obligations undertaken by BPA after September 30, 2006 for commercial purposes (including commercial activities of Transmission Services), such as Resource Support Services, Ancillary Services or other generation inputs to facilitate the sale of transmission, wind integration services, or sales of surplus energy or capacity.

PPG Motion, TRM-12-M-PPG-04, at 3-4.

BPA Staff's Position

In its October 7, 2008, Motion to Supplement the Record and Allow for Comment, BPA proposed a revised definition of Designated BPA System Obligations, as shown below. TRM-12-M-BPA-11, Attachment B. This language was changed as a result of the September 12 and September 30, 2008, settlement discussions to ensure that BPA could not add Designated BPA System Obligations that are for commercial purposes. The proposed language arising from the settlement discussions is shown below.

Designated BPA System Obligations means the set of obligations specified in Table 3.4, or imposed on BPA by statutes, regulations, court order, treaties, executive orders, memoranda of agreement, and contracts, that require the generation or delivery of power, forbearance from generating power, or receipt of power, in order to support the operation of the FCRPS, including any obligations to the BPA Balancing Authority (Transmission Services), and that are not intended for commercial purposes.

Evaluation of Positions

BPA agrees that customers should have as much certainty as reasonably possible about Designated BPA System Obligations and that customers should be reasonably protected against inappropriate new Designated BPA System Obligations that reduce their access to power at the Tier 1 Rates or increase Tier 1 Rates. On the other hand, BPA has a variety of statutory, contractual, and other responsibilities in addition to its responsibility for service to preference customers, and it must preserve its ability to fulfill those other responsibilities. It is necessary for the Administrator to have the ability to enter into memoranda of agreement or contracts that he or she determines are within BPA's authority and serve the best interest of the region. This broad ability to contract originates from section 2(f) of the Bonneville Project Act, was reaffirmed by section 9(a) of the Northwest Power Act, and has been widely recognized by the Ninth Circuit. 16 U.S.C. § 832a(f); 16 U.S.C. § 839f(a); *Ass'n of Pub. Agency Customers v. Bonneville Power Admin.*, 126 F.3d 1158, 1171 (9th Cir. 1997). Staff's proposed definition of Designated BPA System Obligations strikes an appropriate balance between customer desires and BPA's responsibilities to meet all of its obligations.

BPA does not agree with the parties' proposal that, to the extent BPA undertakes a system obligation that dilutes the capability of the Tier 1 System, BPA should acquire the resources necessary to do so without diminishing the output of the Tier 1 System. BPA's obligation is to meet the loads of its Preference customers. Nothing in the TRM or in the definition of Designated BPA System Obligations will compromise BPA's obligation to meet Preference loads. The parties' proposal would increase BPA's overall need to acquire new resources by preventing BPA from using surplus capability of the existing system to serve new obligations. Further, it would likely increase overall costs to regional power consumers by dividing BPA's acquisitions into sequestered pools for separate obligations rather than implementing a least-cost acquisition strategy to meet all of BPA's obligations.

Adopting a strategy that increases the total cost of service to regional consumers is a worse choice than incurring only necessary obligations, implementing the least-cost approach to meeting them, and ensuring through rates that costs of such obligations are fairly distributed. Though it is premature to attempt to establish all the mechanics for doing so now, it is feasible to protect preference customers from unwarranted increased costs (due to new obligations) through appropriate pricing of service to those obligations.

The PPG, supported by WPAG, specifically objects to including Resource Support Services, Ancillary Services, or other generation inputs to facilitate the sale of transmission, wind integration services, or sales of surplus energy or capacity as Designated BPA System Obligations. PPG Motion, TRM-12-M-PPG-04, at 4; WPAG Motion, TRM-12-M-WA-02, at 2.

BPA cannot act on the PPG and WPAG objection in the limited forum that is the TRM 7(i) proceeding. There are significant issues associated with the treatment of BPA reliability obligations that must be addressed in a regional forum open to all stakeholders.

Finally, WPAG mentions the preference customers’ “claim to the output of the FBS” and mistakenly implies that the TRM is a power allocation to preference customers of the Tier 1 System output. WPAG Brief, TRM-12-B-WA-01, at 6-7. It is important to remember that BPA’s fundamental intent as reflected in the TRM is to allocate costs and not to allocate system output or power. BPA sells power consistent with section 5 of the Northwest Power Act. 16 U.S.C. § 839c. BPA is self-financing, and its rates must be set to recover its total system costs. 16 U.S.C. §§ 838i, 839e(a)(2). Accordingly, customers must bear the cost of these obligations that apply to the Federal system as a whole.

Decision

In collaboration with customers, Staff has made significant revisions to section 3.1.4.1, as discussed infra in Issue 2, and the definition of Designated BPA System Obligations to address the parties’ interests. BPA adopts the additional proposed language for section 3.1.4.1 and the definition of Designated BPA System Obligations from Attachment A. However, BPA will not adopt the additional changes proposed by the parties for the second paragraph of section 3.1.4.1 or the definition of Designated BPA System Obligations.

Issue 2

Whether BPA should adopt the proposed changes to the public process for changing Designated BPA System Obligations or revising the amount of Tier 1 System Obligations described in TRM section 3.1.4.1.

Parties’ Positions

The PPG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, Cowlitz PUD, Grays Harbor PUD, and ICNU, and Snohomish, joined by Cowlitz PUD, provided language changes to clarify the purpose and content of the public process and to clarify that the customers could request reasonable information about the costs and revenues associated with system obligations. PPG Brief, TRM-12-B-PPG-01, at 25; Snohomish Brief, TRM-12-B-SN-01, at 4; Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; Canby Joinder, TRM-12-M-CA-01; Cowlitz Joinder, TRM-12-M-CO-01; Grays Harbor Joinder, TRM-12-M-GH-01; ICNU Joinder, TRM-12-M-IN-03;. Further, WPAG suggests language that WPAG claims would provide a meaningful opportunity for preference customers to understand, and debate with BPA, the need for and the size of new Designated BPA System Obligations. WPAG Brief, TRM-12-B-WA-01, at 8. The parties’ proposed language is shown below.

~~To provide customers~~Customers with CHWM Contracts should have as much certainty as reasonably ~~practicable~~possible about Designated BPA System Obligations; that increase the Tier 1 System Obligations, and they should be reasonably protected against new Designated BPA System Obligations that

reduce their access to power at the Tier 1 Rates or increase Tier 1 Rates. Therefore, when possible, BPA will hold a public process before entering into a new Designated BPA System Obligation is added to Table 3.4 or. Where holding such a process is not possible before entering into, or becoming subject to a new Designated BPA System Obligation, BPA will hold such process before a new Designated System Obligation is added to Table 3.4. If the total of existing obligations increases such that BPA's forecast of Tier 1 System Obligations increases, or is expected to increase, by 10 percent over the most recently published forecast of Tier 1 System Obligations. ~~When such a change occurs (even without the addition of any new Designated BPA System Obligation), then BPA shall notify all customers with CHWM Contracts of such change. If as soon as reasonably possible. Upon written request of not less than 25 percent of the customers with CHWM Contracts (by number), BPA cannot will hold a public process prior to implementing a change on the matter. In the public processes described above, BPA will hold at least one open meeting to: (i) in system obligations, then BPA shall notify all customers with CHWM Contracts of the case of new Designated BPA System Obligation or increase in Tier 1 System Obligations within 60 calendar days, review the need for and the amount of such change. Upon written request of not less than 25 percent of the customers with CHWM Contracts (by number), BPA will hold at least one open meeting to obligation; and (ii) in the case of existing Designated BPA System Obligations, review its Designated BPA System Obligations and forecast Tier 1 System Obligation amounts. BPA will respond to reasonable requests to provide information that is non-confidential and is reasonably related to its determination of the amount of new and existing Designated BPA System Obligations, forecast Tier 1 System Obligations, and any revenues or costs associated with such obligations. The purpose of such a meeting(s) is to inform parties of revisions changes to the Tier 1 System Obligations and to allow comment on such revisions.~~ changes. In addition to conducting the open meeting(s), BPA will consider written comments submitted in connection with such meeting(s).

PPG Brief, TRM-12-B-PPG-01, at 25; Snohomish Brief, TRM-12-B-SN-01, at 4; WPAG Brief, TRM-12-B-WA-01, at 8.

After BPA submitted its Motion to Supplement the Record and Allow for Comment, the PPG submitted further revised language, supported by WPAG, regarding section 3.1.4.1. The proposed language restates the desire parties expressed in settlement discussions to require BPA to provide information on revenues or costs associated with changes in Designated BPA System Obligations and increases in Tier 1 System Obligations. The new proposed language is shown by the underlined text in the following excerpt:

In the public processes described above, BPA will hold at least one open meeting to: (i) in the case of new Designated BPA System Obligations review the need for and the amount of such obligation; and (ii) in the case of existing Designated BPA System Obligations, review its forecast of Tier 1 System Obligation amounts. BPA will respond to reasonable requests to provide information that is

nonconfidential and is reasonably related to its determination of the amount of new and existing Designated BPA System Obligations, forecast Tier 1 System Obligations and any revenues or costs associated with such obligations. BPA will consider written comments submitted in connection with such meeting(s). The purpose of such a meeting(s) is to inform parties of changes to the Tier 1 System Obligations and to allow comment on such changes. ~~In contrast,~~ issues related to cost allocation, rate impacts or rate treatment of changes to Designated BPA System Obligations or Tier 1 System Obligations will be addressed in the appropriate RHWB Process or 7(i) Process. ~~In addition to conducting the open meeting(s), BPA will consider written comments submitted in connection with such meeting(s).~~

PPG Motion, TRM-12-M-PPG-04, at 4; WPAG Motion, TRM-12-M-WA-02, at 2.

Finally, the PPG, supported by Snohomish, argued that any additions to Designated BPA System Obligations not required by law or court order should be required to be implemented only through a change to the TRM pursuant to sections 12 and 13. PPG Brief, TRM-12-B-PPG-01, at 23; Snohomish Brief, TRM-12-B-SN-01, at 3.

BPA Staff's Position

As a result of the September 12 and September 30, 2008, settlement discussions, Staff agreed with many but not all of the parties' proposed changes. Staff proposed language that clarifies the types of information that can be requested and better defines the public process BPA will use for new Designated BPA System Obligations or increases in Tier 1 System Obligations. *See*, in pertinent part, proposed language of section 3.1.4.1 below.

Customers with CHWM Contracts should have as much certainty as reasonably possible about Designated BPA System Obligations that increase the Tier 1 System Obligations. Therefore, when possible, BPA will hold a public process before entering into a new Designated BPA System Obligation. Where holding such a process is not possible before entering into or becoming subject to a new Designated BPA System Obligation, BPA will hold such process before a new Designated BPA System Obligation is added to Table 3.4.

If the total of existing obligations increases such that BPA's forecast of Tier 1 System Obligations increases, or is expected to increase, by 10 percent over the most recently published forecast of Tier 1 System Obligations (even without the addition of any new Designated BPA System Obligations), then BPA shall notify all customers with CHWM Contracts of such change as soon as reasonably possible. Upon written request of not less than 25 percent of the customers with CHWM Contracts (by number), BPA will hold a public process on the matter.

In the public processes described above, BPA will hold at least one open meeting to: (i) in the case of new Designated BPA System Obligations, review the need for and the amount of such obligation; and (ii) in the case of existing Designated

BPA System Obligations, review BPA's forecast of Tier 1 System Obligation amounts. BPA will respond to reasonable requests to provide information that is non-confidential and is reasonably related to BPA's determination of new and existing Designated BPA System Obligations or the forecast amount of Tier 1 System Obligations. The purpose of such a meeting(s) is to inform parties of changes to the Tier 1 System Obligations and to allow comment on such changes. In contrast, issues related to cost allocation, rate impacts, or rate treatment of changes to Designated BPA System Obligations or Tier 1 System Obligations will be addressed in the appropriate RHWM Process or 7(i) Process. In addition to conducting the open meeting(s), BPA will consider written comments submitted in connection with such meeting(s).

TRM-12-M-BPA-11, Attachment B.

In addition, Staff proposed some revisions to the definition of Designated BPA System Obligations to provide additional clarity.

Designated BPA System Obligations means the set of obligations specified in Table 3.4, or imposed on BPA by statutes, regulations, court order, treaties, executive orders, memoranda of agreement, or contracts, that require the generation or delivery of power, forbearance from generating power, or receipt of power, in order to support the operation of the FCRPS, including any obligations to the BPA Balancing Authority (Transmission Services), and that are not intended for commercial purposes.

TRM-12-M-BPA-11, Attachment B. The additional language is designed primarily to clarify that BPA's power marketing decisions that are made for commercial purposes rather than to support the operation of the FCRPS or the BPA Balancing Authority are not considered Designated BPA System Obligations.

Evaluation of Positions

In settlement discussions, Staff and the parties collaborated to develop a public process that will provide transparency regarding when BPA may add a new Designated BPA System Obligation or when BPA forecasts that Tier 1 System Obligations may increase by more than 10 percent. In comments by the PPG, supported by WPAG, the parties do not object to Staff's latest proposed language; the parties do however propose additional language that addresses requesting information related to rate impacts, revenues, and costs. PPG Motion, TRM-12-M-PPG-04, at 4; WPAG Motion, TRM-12-M-WA-02, at 2. Staff's proposed language, "BPA will respond to reasonable requests to provide information that is non-confidential and is reasonably related to BPA's determination of new and existing Designated BPA System Obligations or the forecast amount of Tier 1 System Obligations" is sufficiently broad to allow the parties an opportunity to request information on the revenues or costs of a new or existing Designated BPA System Obligation. If parties request information on cost allocations, rate impacts, or rate treatments, those requests are best accommodated in the appropriate RHWM Process or 7(i) Process, both of which occur every two years.

Throughout the settlement discussions, BPA worked with customers to define how BPA may change Designated BPA System Obligations or the forecast amount of Tier 1 System Obligations. BPA was clear that the PPG proposal to change Designated BPA System Obligations only through court order or executive order or pursuant to sections 12 and 13 of the TRM was overly restrictive and could prevent BPA from using the Federal system to meet its statutory obligations.

Decision

BPA adopts the language developed in collaboration with parties for the public process for changing Designated BPA System Obligations and revising the amount of Tier 1 System Obligations as set forth in Attachment B. BPA does not adopt the language changes proposed by the parties for TRM section 3.1.4.1 related to the public process for changing Designated BPA System Obligations and revising the amount of Tier 1 System Obligations.

Issue 3

Whether BPA should adopt the language for the definition of Discretionary Contracts and section 3.1.4.2 Discretionary Contracts.

Parties' Positions

The PPG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, Cowlitz PUD, Grays Harbor PUD, and ICNU; Snohomish, joined by Cowlitz PUD; and WPAG, joined by McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, and GP, propose language revising the definition of Discretionary Contracts, as shown below.

Discretionary Contracts means those purchases, sales, and exchanges ~~Designated BPA Contract Purchases and Designated BPA System Obligations~~ that have resulted from BPA power marketing transactions as of September 30, 2006, decisions by Power Services and are identified on Tables 3.3 and 3.4.

PPG Brief, TRM-12-B-PPG-01, at 26; Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; Canby Joinder, TRM-12-M-CA-01; GP Joinder, TRM-12-M-GP-05; Cowlitz Joinder, TRM-12-M-CO-01; Grays Harbor Joinder, TRM-12-M-GH-01; ICNU Joinder, TRM-12-M-IN-03; Snohomish Brief, TRM-12-B-SN-01, at 5; WPAG Brief, TRM-12-B-WA-01, at 8. The PPG states that it understands, as stated in section 3.1.4.2 of the TRM, that Discretionary Contracts consist of transactions entered into by BPA on or before September 30, 2006, and resulting from marketing decisions. PPG Brief, TRM-12-B-PPG-01, at 26. However, the PPG contends that the definition appears to be in conflict with section 3.1.4.2 and that the proposed revisions will add clarity and avoid potential

ambiguity or conflict. *Id.* During settlement discussions, the parties proposed clarifying changes to section 3.1.4.2, as shown below.

3.1.4.2 Discretionary Contracts

Discretionary Contracts consist of BPA purchases, sales, and exchanges resulting from BPA marketing transactions as of September 30, 2006. These contracts are identified in Tables 3.3 and 3.4 in the column titled Discretionary Contracts.

Discretionary Contracts shown in Tables 3.3 and 3.4 will not be replaced upon expiration. Any costs pertaining to or revenues recovered from the listed

Discretionary Contracts will be assigned to the Composite Cost Pool.

Discretionary Contracts entered into after September 30, 2006, will not be added to Table 3.3 or 3.4 ~~(and therefore will not increase or decrease Tier 1 System Firm Critical Output.)~~ but ~~a~~Any costs pertaining to or revenues recovered from such new Discretionary Contracts will be assigned to the Non-Slice Cost Pool.

BPA Staff's Position

Through BPA's October 7, 2008, Motion to Supplement the Record and Allow for Comment, Staff proposed the parties' language for the definition of Discretionary Contracts, as shown below. In rebuttal testimony, Staff had already included the language for TRM section 3.1.4.2 agreed to in settlement discussions, as noted above. TRM-12-E-BPA-20 at 22-23. *See* proposed language below.

Discretionary Contracts means those purchases, sales, and exchanges resulting from BPA marketing transactions as of September 30, 2006, and identified on Tables 3.3 and 3.4.

3.1.4.2 Discretionary Contracts

Discretionary Contracts consist of BPA purchases, sales, and exchanges resulting from BPA marketing transactions as of September 30, 2006. These contracts are identified in Tables 3.3 and 3.4 in the column titled Discretionary Contracts.

Discretionary Contracts shown in Tables 3.3 and 3.4 will not be replaced upon expiration. Any costs pertaining to or revenues recovered from the listed

Discretionary Contracts will be assigned to the Composite Cost Pool.

Discretionary Contracts entered into after September 30, 2006, will not be added to Table 3.3 or 3.4 and therefore will not increase or decrease Tier 1 System Firm Critical Output. Any costs pertaining to or revenues recovered from such new Discretionary Contracts will be assigned to the Non-Slice Cost Pool.

TRM-12-M-BPA-11, Attachment A.

Evaluation of Positions

The PPG, Snohomish, and WPAG submitted briefs supporting the revision of the definition of Discretionary Contracts. PPG Brief, TRM-12-B-PPG-01, at 26; Snohomish Brief, TRM-12-B-SN-01, at 5; WPAG Brief, TRM-12-B-WA-01, at 8. In subsequent settlement discussions, the

parties did not raise any further issues related to the definition of Discretionary Contracts or section 3.1.4.2, Discretionary Contracts. In response to the parties' request, Staff incorporated the parties' proposed language exactly as proposed. TRM-12-M-BPA-11 at Attachment A; TRM-12-E-BPA-20 at 22-23.

The PPG and WPAG generally accept BPA's revision of the definition of Discretionary Contracts. PPG Motion, TRM-12-M-PPG-04, at 2; WPAG Motion, TRM-12-M-WA-02, at 1. However, in their motions, the PPG and WPAG also proposed a significant addition to section 3.1.4.2, as shown below in underlined text. The proposed changes to section 3.1.4.2 were not raised by the parties in their briefs; nor was the proposal raised and discussed in the two settlement conferences held after the parties submitted their briefs. Accordingly, Staff did not include any proposed changes to section 3.1.4.2 in the October 7, 2008, Motion to Supplement the Record and Allow for Comment. WPAG also urges BPA to adopt the second paragraph to section 3.1.4.2 in the redlined version below, while acknowledging that this language was developed solely by public power representatives subsequent to the September 12, 2008, settlement discussion without consultation of BPA or other rate case parties. WPAG Motion, TRM-12-M-WA-02, at 2.

3.1.4.2 Discretionary Contracts

Discretionary Contracts consist of BPA purchases, sales, and exchanges resulting from BPA marketing transactions as of September 30, 2006. These contracts are identified in Tables 3.3 and 3.4 in the column titled Discretionary Contracts.

Discretionary Contracts shown in Tables 3.3 and 3.4 will not be replaced upon expiration. Any costs pertaining to or revenues recovered from the listed Discretionary Contracts will be assigned to the Composite Cost Pool.

Discretionary Contracts entered into after September 30, 2006, and any purchase, sale, and exchange resulting from settlement of Discretionary Contract disputes, will not be added to Table 3.3 or 3.4 and therefore will not increase or decrease Tier 1 System Firm Critical Output. Any costs pertaining to or revenues recovered from such new Discretionary Contracts will be assigned to the Non-Slice Cost Pool.

If a new Discretionary Contract has a term of thirty-six (36) months or longer, then BPA will include in each such Discretionary Contract either: (i) a provision allowing BPA to curtail delivery of the surplus capacity or energy sold under the Discretionary Contract upon twenty-four (24) months prior written notice if such surplus capacity or energy is needed by BPA to serve firm requirements load in the region, or (ii) a provision allowing BPA to adjust the price at which the surplus capacity or energy is sold under the Discretionary Contract to reflect the costs of any replacement capacity or energy acquired by BPA to fulfill its obligations under the Discretionary Contract when there is no longer sufficient surplus energy or capacity available from the Tier 1 System Resources to enable BPA to fulfill such obligations. In no event will BPA decrease the amount of surplus energy and capacity available under the Block/Slice Power Sales Agreement for the purpose of directly or indirectly supporting new Discretionary Contracts.

PPG Motion, TRM-12-M-PPG-04, at 6.

BPA cannot accept this last-minute proposal to change the TRM. The first portion of the parties' new language directs BPA to allocate to the Composite Cost Pool costs associated with any settlement related to Discretionary Contracts. This proposed change is confusing, as it does not distinguish between treatment for Discretionary Contracts prior to September 30, 2006, and such contracts BPA may enter into after September 30, 2006. Additionally, the issue of treatment for settlements is already addressed by the assignment of the costs pertaining to, or revenues recovered from, the cost pool to which the Discretionary Contract is assigned. The addition of this second reference to the treatment of settlement cost creates only greater ambiguity regarding the treatment of these costs.

The second portion of the parties' new language proposes limitations and specific provisions that would apply to BPA sales of surplus energy or capacity entered into as part of any new Discretionary Contract. These proposed changes seem to be designed to limit or restrict BPA's contractual authority to enter into surplus sales agreements using the Federal system to meet BPA's contractual and statutory obligations. Such language is not something to which BPA will agree. It is not applicable to a rate methodology and thus is inappropriate to include in the TRM.

The parties' proposed language further states that in no event will BPA decrease the amount of surplus energy and capacity available under the Block/Slice Power Sales Agreement for the purpose of directly or indirectly supporting new Discretionary Contracts. PPG Motion, TRM-12-M-PPG-04, at 6. WPAG supports the PPG proposed language. WPAG Motion, TRM-12-M-WA-02, at 2.

This language is directly related to the amount of surplus power available to a party that signs a Slice/Block contract. This language seems to be attempting to define or modify terms and conditions that are part of the Slice/Block contract. The Slice/Block contract has specific terms and conditions that establish the amount of energy and scheduling flexibility available to a customer and define how surplus power amounts are determined and made available. Slice/Block Power Sales Agreement, sections 5.1, 5.2, 5.5, 5.6, Exhibit M – Slice Computer Application and Exhibit N – Slice Implementation Procedures. This proposed change in the language of the TRM is inconsistent with the terms of the Slice/Block contract and is not properly a part of a rate design methodology.

In settlement discussions, Staff and the parties refined the definition of Discretionary Contracts and the language in section 3.1.4.2 to improve clarity and reduce ambiguity. The latest PPG proposed changes to section 3.1.4.2 were suggested after the language of the section was understood to be settled. As discussed above, these last-minute changes add only confusion, address issues that are already adequately dealt with elsewhere in the TRM, inappropriately introduce contract matters into a rate methodology, improperly address BPA's contractual authority, conflict with BPA contract language, and generally introduce new issues that had not been raised previously. For all these reasons, BPA cannot adopt the new proposed language for section 3.1.4.2.

Decision

BPA adopts the language previously developed in collaboration with and accepted by parties for the definition of Discretionary Contracts and changes to TRM section 3.1.4.2 as set forth in BPA's Motion to Supplement the Record and Allow for Comment, Attachment B. BPA will not adopt any of the language changes proposed in motions by the parties for TRM section 3.1.4.2, Discretionary Contracts.

3.3 Eligibility to Purchase at Tier 1 Rates

3.3.1 Introduction

Section 4 of the TRM describes the functions of and processes for developing High Water Marks. These include the Transition Period HWM (THWM), Contract HWM (CHWM), and Rate Period HWM (RHWM). The fundamental purpose of these HWMs is to define a customer's eligibility to purchase power from BPA at Tier 1 Rates on a forecast, benchmarked, or planned basis.

Through collaboration with interested parties in public meetings, Staff developed a proposal for this section of the TRM that was accepted by the parties, *see* TRM-12-E-BPA-20 at 30, with the exception of certain issues raised in the parties' briefs. The issues raised in the briefs concerning this section of the TRM concern increases in CHWMs for CF/CT loads and for small New Publics. *See* briefs of Clatskanie, TRM-12-B-CK-01; GP, TRM-12-B-GP-01; ICNU, TRM-12-B-IN-01 regarding CF/CT loads, and ATNI, TRM-12-B-AT-01, regarding small New Publics. Those issues are addressed, respectively, in sections 2.0 and 7.2.2 of this ROD.

3.3.2 Changes to Attachment D

Attachment D to the TRM, Conservation Adjustment, sets forth an example of how this adjustment to CHWM works for a utility. Certain changes need to be made to TRM Attachment D, because they were inadvertently not included in the last TRM draft that was filed in this proceeding. The changes made were to conform Attachment D to the rest of the TRM and have no substantive impact on the conservation adjustment calculation results. The development of the TRM included changing the application of several terms and revising how certain formulas were expressed. The Attachment D to the last filed draft TRM did not correctly reflect certain of those changes. The following changes have been made (see underlined and struck through language):

- a. Page D-1:
 - 4) Row 5 shows the calculation of the rebalancing factor by taking the sum of the individual Scaled Eligible Loads and dividing it by the sum of the conservation-adjusted Scaled Eligible Load for all utilities (7,470 aMW; the sum of the calculation of all the utilities' Scaled Eligible Load plus the total conservation by all utilities).

5) Row 6 shows the CHWM—calculated by multiplying the rebalancing factor by the ~~Tier 1 System Capability~~ customer’s conservation-adjusted Scaled Eligible Load (row 5 × ~~7,300 aMW~~ Row 4).

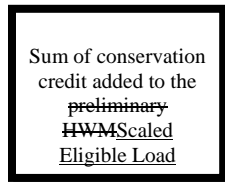
b. Page D-2:

Assumptions: Tier 1 System Capability amount = 7300 aMW, including a 100 aMW ~~RP~~

c. Page D-2, lines 3-4 of the Scenario table –

3	Scaled Eligible Load (<u>SEL</u>) calculation	100	99	97
4	Conservation-adjusted CHWM <u>SEL</u>	100	100	100

d. Page D-3, last box of the flowchart –



3.3.3 Calculation of CHWMs for CF/CT Load

Clatskanie, GP, and ICNU raise several legal issues regarding BPA’s proposal to serve preference customers’ above-RHWM CF/CT load growth at Tier 2 rates. Those legal issues are addressed in ROD section 2.0.

3.3.4 Increasing CHWMs for Small New Publics

Issue 1

Whether BPA should increase the number of small New Publics that are provided additional CHWM under TRM section 4.1.6.3.1.

Parties’ Positions

ATNI commented that the TRM contains limitations on the access of New Publics to the benefits of the FCRPS that are contrary to BPA’s statutory charge to ensure widespread use of those benefits. ATNI Brief, TRM-12-B-AT-01, at 2 and 8-11. ATNI stated that the TRM should encourage the formation and expansion of any New Tribal Utility with power sold at Tier 1 Rates. *Id.* at 11-12. ATNI claimed that the exception for five small utilities under the 50 aMW Rate Period limit for New Publics should be expanded. *Id.* at 12-13. ATNI also stated that the TRM notice provisions for service to New Publics under tiered rates are unduly restrictive and will limit New Public formation. *Id.* at 13-15.

BPA Staff's Position

Staff noted that the TRM provides an exception for the first five small New Publics to the phasing-in requirements for utilities when requests for new service in a Rate Period exceed the 50 aMW limit. TRM-12-E-BPA-20 at 41-42. Those small New Publics will have their CHWMs increased in an amount equal to the amount that they would have otherwise been prorated downward. *Id.*

Staff engaged in discussions with ATNI, resulting in a proposal that if BPA were to increase from five to ten the number of small New Publics eligible for the phase-in exception, then ATNI would be willing to drop the remainder of issues that it had raised in its brief. *See* ATNI Brief, TRM-12-B-AT-01, at 1-2. Staff subsequently proposed modifications to the TRM to increase the phase-in exception from five to ten. *See* TRM-12-M-BPA-11, Attachment A.

Evaluation of Positions

BPA agrees with the position stated in ATNI's brief that the increase in exceptions for New Publics will not pose resource planning issues for BPA and will not significantly increase rates for other customers receiving power at Tier 1 Rates. The benefit of achieving consensus on this issue with ATNI clearly supports granting the increase in exceptions for New Publics.

Subsequent to filing its brief, ATNI filed its Motion Commenting on Proposed TRM Changes. In that motion, ATNI stated that the points it argued in its brief are no longer at issue, contingent on (1) final approval of the Administrator of the proposed change to section 4.1.6.3.1 of the TRM, as set forth in Attachment A of TRM-12-M-BPA-11 and (2) other provisions of the TRM related to New Publics or interests of ATNI remaining unchanged from the current TRM proposal. ATNI Motion, TRM-12-M-AT-03, at 1-2.

The relevant sentence of TRM section 4.1.6.3.1 now reads:

These additional amounts will exceed the 50 aMW Rate Period limit. This exception is limited for the duration of this TRM to the first ~~five~~ten requesting utilities that meet the size threshold and that would otherwise have had their CHWM prorated downward due to application of the 50 aMW Rate Period limit.

BPA adopts the change to TRM section 4.1.6.3.1, and the other provisions related to New Publics and other interests of ATNI remain unchanged from the TRM filed with Staff's rebuttal. Thus, BPA has met the conditions described by ATNI, and the issues ATNI raised in its brief are resolved.

Decision

BPA adopts an increase from five to ten for the number of small New Publics that are provided additional CHWM as described in TRM section 4.1.6.3.1.

3.4 Tier 1 Rate Design

3.4.1 Demand Charge

Issue

Whether there is evidence in the record that substantiates that BPA lacks sufficient FBS resources to allow it to price the Demand Charge at a marginal price.

Parties' Positions

WPAG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, and GP, states that the TRM should ensure that Preference Customers receive the maximum service possible from the FBS at embedded cost before market prices are imposed on preference customers. WPAG Brief, TRM-12-B-WA-01, at 9; Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; Canby Joinder, TRM-12-M-CA-01; GP Joinder, TRM-12-M-GP-05. WPAG contends that the design of the Demand Charge forces customers to pay rates based upon marginal prices even though FBS resources may be available to provide this service. WPAG Brief, TRM-12-B-WA-01, at 10. WPAG states that BPA has offered no evidence that the 10 percent reduction to the grandfathered demand is based on the inability of the FBS to serve the full amount of demand grandfathered by the CDQ. *Id.*

BPA Staff's Position

Because neither WPAG nor any other party raised this issue during the evidentiary phase of this proceeding, BPA Staff did not present any evidence regarding the availability of FBS resources or the lack thereof to meet customers' demand.

The Demand Charge was designed to send customers with Load Following and Block with Shaping Capacity contracts a marginal price signal for a portion of the customers' existing Demand. TRM-12-E-BPA-01, at 65. Staff's rate design for the proposed Demand Charge placed some amount of existing demand on the margin to encourage demand reduction programs (i.e., Demand Side Management (DSM)) for all Load Following and Block with Shaping Capacity customers regardless of whether they are growing or not. Fisher, *et al.*, TRM-12-E-BPA-06, at 24.

Grandfathering 91 percent of a customer's historical peak load would result in providing an accurate price signal while keeping the total charges for all components of the rate design similar to those under the current rate design. *Id.*

Evaluation of Positions

WPAG contends that the TRM generally does not provide preference customers with the maximum service possible from the FBS at embedded cost before market prices are imposed.

WPAG Brief, TRM-12-B-WA-01, at 9. As an example, WPAG points to the Demand Charge where, WPAG contended, customers are required to pay rates based upon marginal prices even though FBS resources may be available to provide this service. *Id.* at 10. WPAG argues that BPA has offered no evidence that the 10 percent reduction to the grandfathered demand is based on the inability of the FBS to serve the full amount of demand grandfathered by the CDQ. *Id.* WPAG does not specify what changes should be made to the TRM to address this perceived problem, but the implication is that BPA should “grandfather” all historical demand to the extent that FBS resources are available to provide the service. *Id.* The result of this practice, and apparently what WPAG favors, is that BPA would charge embedded costs for the Demand Charge to the extent there are FBS resources available. *Id.* WPAG does not cite any statutory authority to support this position.

Because no party raised this issue during the proceeding, Staff did not address the specific issue raised by WPAG. While there is no evidence in the record regarding the availability of the FBS to provide this service, that issue is secondary to a more fundamental question; namely, whether it is appropriate for BPA to price products and services to send marginal price signals. If it is appropriate for BPA to use marginal cost-based pricing to provide price signals to customers, irrespective of whether the product or service is supplied by FBS resources, it is irrelevant whether there is evidence in the record regarding whether there are FBS resources available to supply this service.

WPAG does not state whether it was challenging BPA’s legal authority to price the Demand Charge based on marginal cost or the policy decision to do so. Because WPAG argues that Staff failed to present evidence that there is no FBS available to provide this service, it would appear that WPAG’s concern is a legal one as opposed to a policy decision. Nevertheless, this ROD will evaluate WPAG’s argument from both perspectives.

WPAG’s argument goes to the heart of the discretion granted to BPA’s Administrator regarding the design and form of rates. The following will not repeat the entirety of the earlier discussion of the legality of tiered rates and the discretion granted by Congress. *See* section 2.0, Issue 2, *supra*. However, a summary of the relevant points is set forth here.

The Northwest Power Act grants the Administrator broad discretion in the design of rates. This broad discretion is found in section 7(e) of the Act, 16 U.S.C. § 839e(e), which provides that “[n]othing in this Act prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or other rate forms.” The Ninth Circuit Court of Appeals has recognized this authority, finding that “the statute does not require BPA to impose any particular type of rate on its customers. Rather it restricts BPA only to ‘sound business principles’ in setting rates to meet its revenue requirements.” *City of Seattle v. Johnson*, 813 F.2d 1364, 1367 (9th Cir. 1987). Particular rate directives provide what costs BPA may recover from customer classes, but the directives do not prescribe the rate form or forms, meaning that BPA may sub-allocate costs within the rate class to achieve rate objectives and may design rates to send price signals.

In fact, the Ninth Circuit has previously approved the Commission’s confirmation of rates much like the ones at issue here that were designed “to price electricity on the basis of the cost of

producing it in the future, rather than on the embedded costs of production.” *Central Lincoln Peoples’ Utility District. v. Johnson*, 735 F.2d 1101, 1121 (9th Cir.1984). The Court noted that the Northwest Power Act “specifically allows the Administrator latitude in choosing rate forms” and has as a main purpose to encourage “conservation and efficiency.” *Id.* at 1122, *citing* 16 U.S.C. § 839e(e) and 16 U.S.C. § 839(1). The point of such ratemaking is to “encourage efficiency and conservation by enabling customers to make informed consumption decisions based on the costs of producing each type of electric power.” *Id.* at 1121. This is exactly the same logic used to develop the proposed Demand Charge rate design in this proceeding. Despite WPAG’s suggestions to the contrary, it is a proper exercise of statutory ratemaking authority that “permits rate forms ‘designed to give BPA customers price signals.’” *Id.* at 1122, *citing* H.R. Rep. No. 96-976, Part II, 96th Cong., 2d Sess. 53 (1980).

The price signals sent through the Demand Charge are an important aspect of the Regional Dialogue Policy. One of these policy goals is the promotion of regional electric infrastructure. RD Policy, at 5. BPA staff testified that it believes the price signal associated with Demand Charge will pass on to customers the actual cost of capacity and will encourage new resource development, as well as better inform customers’ resource development decisions. *Cherry, et al.*, TRM-12-E-BPA-02, at 15. The Demand Charge also supports BPA’s second RD Policy goal of keeping Tier 1 Rates low and stable. RD Policy, at 6. The RD Policy states that BPA will keep Tier 1 Rates low and stable by limiting the amount of energy that is included in the Tier 1 System Resources. However, BPA will also need to acquire capacity to meet its demand obligations. Unlike with energy, the TRM does not place a limit on the amount of additional demand placed on BPA. This means customers have a potentially unlimited access to capacity. Therefore, without the inclusion of a marginal price signal with the Demand Charge, there is no mechanism for collecting these added costs, thus jeopardizing the goal of low and stable rates.

Furthermore, price signals are not new to BPA. BPA believes there are significant benefits of including price signals in its cost-based rates and has included marginal price signals in many of its previous rate designs. As documented in the WP-96 rate case, there is a reasonable policy objective behind Staff’s proposal to charge a marginal cost-based price for demand. Contrary to WPAG’s contention, the objective of the TRM is not solely to provide the maximum service possible from the FCRPS at the cost of service. Staff’s goal for the Demand Charge is to send a price signal to a limited portion of a customer’s overall demand on BPA, to provide an incentive to lower existing peak demand on BPA. Staff hopes to encourage demand reduction programs; pricing some portion of a customer’s demand at the margin will send accurate price signals that should foster the development of these programs. Grandfathering 91 percent of a customer’s historical peak load will balance the competing objectives of providing a price signal while keeping the total charges for all components of the rate design similar to those under the current rate design. *Fisher, et al.*, TRM-12-E-BPA-06, at 24.¹²

Staff developed the concept of “grandfathering” a portion of a customer’s demand during a series of workshops with interested parties, including WPAG, prior to the start of this proceeding.

¹² WPAG makes a similar contention in the context of the Diurnal Flattening Service, Resource Shaping Charge, and Load Shaping Charge, which are addressed in the following issues. The response to the argument here regarding the Demand Charge is equally applicable to the next two issues: namely, the TRM is not solely intended to provide the maximum service from the FCRPS at the cost of service.

During those workshops, Staff and the customers explored grandfathering various percentages of the demand. Cherry, *et al.*, TRM-12-E-BPA-02, at 20. After testing various options in rate impact models, Staff and customers agreed that 91 percent struck the appropriate balance between the policy objective of providing a price signal to some portion of existing demand and the desire to avoid unnecessarily dramatic rate impacts. *Id.* While Staff had the objective of having some amount of existing load on the margin, the primary driver behind Staff's proposed grandfathered percentage was the rate impact (keeping most, if not all, customer total rate impacts below 5 percent simply due to a change in rate design). Fisher, *et al.*, TRM-12-E-BPA-06, at 24.

WPAG's argument with the Demand Charge methodology focuses on the fact that the Demand Rate will be priced at the margin, but ignores the actual application of that rate. While it is true that the Demand Rate will be considerably higher than in the WP-07 Demand Rates, the demand Billing Determinant to which that rate is applied is significantly smaller. Fisher, *et al.*, TRM-12-E-BPA-06, at 4. Because of the smaller Billing Determinant, the total revenues collected by the Demand Charge are expected to be roughly a third of what is currently being collected through the Demand Charge under the WP-07 rate schedules. Therefore, contrary to WPAG's argument, under the TRM BPA expects to collect less revenue through the Demand Charge in the WP-12 Rate Period than BPA does under the current untiered rate design.

Staff's rate design proposal is consistent with BPA's objectives of encouraging efficiency and conservation. By pricing a portion of a customer's demand at the margin, BPA will encourage the development of programs designed to temper customers' demand on BPA. Through this price signal, BPA will foster demand-side management as well as conservation and encourage the efficient use of the FCRPS. These goals are accomplished without a significant increase in the total power bills of any individual BPA customer and while still collecting the same revenue requirement.

Decision

BPA's Demand Charge is based on the record and a reasonable exercise of the Administrator's discretion to design PF rates.

3.4.2 Load Shaping Charge

Issue

Whether the overall design of the Load Shaping Charge (LSC) and the proposed method for determining the Monthly/Diurnal Billing Determinant are appropriate.

Parties' Positions

WPAG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, and GP, notes that the Load Shaping Charge either charges or credits a customer at "market prices" for the amount of power a customer's load is either over or under

the rate case forecast of that load in a particular month. WPAG Brief, TRM-12-B-WA-01, at 10; Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; Canby Joinder, TRM-12-M-CA-01; GP Joinder, TRM-12-M-GP-05. WPAG states that Staff offered no evidence that the FBS is incapable of serving these variations in a customer's load within a month in order to justify charging or crediting market prices for the power. WPAG Brief, TRM-12-B-WA-01, at 10. WPAG argues that the preference customers were not seeking perfect symmetry between service to preference customer loads and market revenues from secondary sales. *Id.* at 11. Instead, the preference customers seek maximum service at the embedded cost of the FBS, and the design of the LSC is inconsistent with this objective. *Id.* WPAG also states that the LSC would make more sense if the preference customers had the assurance that the secondary revenues as forecast by BPA will be used to reduce the Tier 1 Rates to be paid by preference customers. *Id.*

BPA Staff's Position

Because neither WPAG nor any other party raised this issue during the evidentiary phase of this proceeding, BPA Staff did not present any evidence regarding the availability of FBS resources or the lack thereof to meet the shape differences in a customer's load.

Block and Load Following products require BPA to shape the firm critical output of Tier 1 System Resources to a customer's load. TRM-12-E-BPA-20 at 55-56. As a consequence, the LSC is a price signal that reflects the costs associated with balancing loads and resources (Balancing Power Purchases). *Id.*

There are two reasons Staff proposed to diverge from the status quo method for sending energy price signals; i.e., charging diurnal energy prices. The first reason is that customer representatives seemed to prefer a customer charge that would create a common means of collecting costs from all preference customers, regardless of product choice. Cherry, *et al.*, TRM-12-E-BPA-02, at 15. The second reason for the design of the proposed LSC was to remove some of the contention that can develop with load forecast error/biasing, since forecasts would be determining a customer's Above-RHWM Load. Fisher, *et al.*, TRM-12-E-BPA-06, at 18.

Evaluation of Positions

WPAG does not state whether it was challenging BPA's legal authority to price the LSC using a marginal cost basis or the policy decision to do so. Because WPAG argues that Staff failed to present evidence that there is no FBS available to provide this service, it would appear that WPAG's concern is a legal one as opposed to a policy decision. Nevertheless, this ROD will evaluate WPAG's argument from both perspectives.

Because no party raised this issue during the proceeding, Staff did not address the specific issue raised by WPAG during the evidentiary phase of this proceeding. While there is no evidence in the record regarding the availability of the FBS to provide this service, that issue is secondary to a more fundamental question; namely, whether BPA can price products and services using a

marginal price construct, irrespective of whether it has FBS resources available to provide the product or service. As noted in section 3.4.1 of this ROD, BPA has the authority to include price signals in its rate design, as long as BPA recovers its overall revenue requirement. The reasons articulated in response to that issue are equally applicable here.

To the extent that WPAG is challenging the policy decision to send customers price signals with the LSC, BPA stated in the RD Policy a cost causation principle related to the design of the LSC. The RD Policy provides as follows:

... BPA will propose to design the rates for these shaping services so that the projected reshaping costs are recovered from the customers that use the services. To do this, BPA would compare the costs of the shape of the FBS under critical water with the cost to provide the same amount of energy in the load shape required by the customers. Customers purchasing the Load-Following product with shaping services would be required to pay charges to reshape power from the FBS into the shape of their product. In addition, customers that purchase load-following products would pay for the costs and risks BPA faces for serving their actual loads compared to their forecast load...

BPA believes it is important to collect shaping costs in this manner to (a) ensure that customers or classes of customers whose load and resource shapes cause BPA to incur shaping costs pay those costs; (b) help ensure that available capacity and flexibility of the Federal system is put to best use; and (c) help keep the total cost of Tier 1 service low by potentially reducing future supplemental purchases to increase system flexibility or capacity. BPA may need to make long term acquisitions or purchases of resources to increase system flexibility or capacity used in providing shaping services for Tier 1. How the costs of such long-term purchases would be identified and recovered in rates will be addressed in the TRM. The separation of shaping costs in Tier 1 ratesetting will ensure that, in combination, BPA's Tier 1 rates to preference customers will be cost-based, that is, they will be established to recover BPA's Tier 1 rate revenue requirement consistent with the provisions of the BPA Debt Refinancing Act of 1996.

RD Policy at 23. Contrary to WPAG's suggestion, the TRM, and the LSC in particular, are not designed merely to provide customers with "maximum service at embedded cost." WPAG Brief, TRM-12-B-WA-01, at 11. The RD Policy clearly articulates an intention for the LSC to recover the costs associated with providing the service.

The LSC is designed to send a marginal cost-based price signal for different load shapes and effectively allocate the forecast Balancing Power Purchase costs to each utility based on the customer's contribution to BPA's forecast need for Balancing Power Purchases. Fisher, *et al.*, TRM-12-E-BPA-06, at 15. In addition, the LSC helps reduce disputes surrounding the load forecasts used to determine Above-RHWM Load. *Id.* at 18. As noted in section 3.4.1, BPA believes there are benefits to including price signals in its rate designs and has done so in many rate designs prior to the TRM. The reasons articulated in response to that issue are equally applicable here.

WPAG claims that the LSC runs counter to embedded cost pricing, because the LSC rates are equal to a market forecast. WPAG Brief, TRM-12-B-WA-01, at 11.

WPAG's point overlooks the annual application of the LSC and that no annual energy needs (aside from the 8,760 MWh threshold, Fisher, *et al.*, TRM-12-E-BPA-06, at 30) are expected to be served at the Load Shaping Rates; in other words, the number of megawatthours paying a charge will be equal to the number of megawatthours receiving a credit. *Id.* at 4. The LSC is simply a marginal cost-based price signal that allocates the costs of shaping the Firm Critical Output to meet BPA's preference load shape. *Id.* at 15.

Moreover, WPAG's focus on the LSC without consideration of the interaction with the Customer Charges led WPAG to reach a false conclusion that the LSC is in some way different from the 24 shaped HLH and LLH energy rates BPA developed in the WP-02 and WP-07 section 7(i) proceedings.

Staff demonstrated in numerous workshops the interaction between the Customer Charge and LSC components and the juxtaposition against a HLH and LLH energy rate design. It was during those demonstrations that public power representatives coalesced around a general concept that formed the core of the rate design included in the TRM. Cherry, *et al.*, TRM-12-E-BPA-02, at 15.

WPAG also tries to make a connection between the LSC and BPA's secondary revenues. This argument is misplaced, because the LSC is designed to reflect the costs incurred by BPA for Balancing Power Purchases (power purchases or resource acquisitions forecast by BPA in a 7(i) Process to be made by BPA during a Rate Period for periods within a year during which the Tier 1 System Capability is insufficient to meet BPA's Forecast Tier 1 Loads; TRM-12-E-BPA-20 at vii) and not to charge or credit for a cost/benefit related to secondary revenues. Fisher, *et al.*, TRM-12-E-BPA-06, at 15. In fact, the billing determinants for the LSC are the difference between a customer's Tier 1 Monthly/Diurnal load and the generation output of Tier 1 System Resources. The existence of a positive Billing Determinant (which occurs when a customer's load is greater than a pro rata share of the RHWM Tier 1 System Capability for a particular Monthly/Diurnal time period) demonstrates that the Tier 1 System cannot produce enough energy to serve customers' loads in a particular billing period, thus undermining WPAG's argument to the contrary.

Decision

Staff's proposed design of the Load Shaping Charge and the proposed method for determining the Monthly/Diurnal Billing Determinant are appropriate.

3.5 Tier 2 Resource Cost Reallocation

Issue

Whether BPA should revise the TRM statement on the reallocation of the costs of resources allocated to Tier 2 Cost Pools when the need for the resources is less than the output of the resources.

Parties' Positions

The PPG, joined by Clatskanie, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, Cowlitz PUD, and Grays Harbor PUD, noted that the proposed TRM allowed that if the output of new Federal resources exceeds the needs of the Cost Pool(s) for which the resource has been acquired, then the resource may be remarketed to another Cost Pool “at the cost of the resource.” PPG Brief, TRM-12-B-PPG-01, at 27; Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; Canby Joinder, TRM-12-M-CA-01; Cowlitz Joinder, TRM-12-M-CO-01; Grays Harbor Joinder, TRM-12-M-GH-01. The PPG stated that if one Cost Pool is forced to either buy or sell energy or services from another Cost Pool at the underlying cost the selling Cost Pool incurred for the resource, and if that cost differs from market value, then one of the Cost Pools is in fact disadvantaged by the need to enter into the transaction with the other Cost Pool. PPG Brief, TRM-12-B-PPG-01, at 27. The PPG proposed section 3.4 language to correct this potential of being disadvantaged:

Costs of a Federal resource acquisition made after September 30, 2006, will be allocated to one or more Cost Pools. Such costs will remain as allocated for the duration of the resource purchase or the CHWM Contract, whichever ends sooner. If the available power from such resources exceeds the loads that pay such costs, however, then the excess may be forecast to be remarketed. ~~Such remarketing may be to another Cost Pool at the cost of the resource. Any revenues resulting from the remarketing of such resource will be credited to the Cost Pool to which the cost of such resource is allocated.~~ For ratemaking purposes, such remarketing will be forecast to occur at the market price of power during the period when the remarketing occurs, as forecast in the applicable 7(i) Process, and the revenues resulting from such remarketing will be credited, in proportion to their contribution of excess power, to the Cost Pool(s) to which the cost of such resource is allocated.

PPG Brief, TRM-12-B-PPG-01, at 28.

BPA Staff's Position

BPA Staff proposed to reallocate from one cost pool to another “at the cost of the resource.” TRM-12-E-BPA-20 at 26. Staff engaged parties to resolve the difference in proposed language.

Evaluation of Positions

As a result of settlement discussions on September 30, 2008, Staff proposed modifications to TRM section 3.4, as follows:

3.4 Allocation of Costs for New Federal System Resource Acquisitions

Costs of a Federal resource acquisition made after September 30, 2006, will be allocated to one or more Cost Pools. Such costs will remain as allocated for the duration of the resource purchase or the CHWM Contract, whichever ends sooner. If the available power from such resources exceeds the loads that pay such costs, however, then the excess may be forecast to be reallocated to another Tier 2 Cost Pool, if one is available, to Augmentation for Initial CHWM, or to Augmentation for Additional CHWM, if such a need exists. In the event there is no Tier 2 Cost Pool to which the power may be reallocated, or there is no need of such power for purposes of Augmentation for Initial CHWM or Augmentation for Additional CHWM, such power will be deemed to be surplus power available for sale. For ratemaking purposes, in all such circumstances such reallocation or marketing will be forecast to occur at the market price of power during the period when the reallocation occurs, as forecast in the applicable 7(i) Process, and the revenues resulting from such reallocation will be credited, in proportion to their contribution of excess power, to the Cost Pool(s) to which the cost of such resource is allocated. In the event such power is not reallocated to another Cost Pool, to Augmentation for Initial CHWM or to Augmentation for Additional CHWM, BPA may include a risk component or adjustment mechanism for the risk associated with the potential difference between forecast and actual market prices.

TRM-12-M-BPA-11, Attachment A. The PPG agrees that Staff's proposal would resolve its issue. PPG Motion, TRM-12-M-PPG-04, at 7-8. Thus, all those joining with the PPG are deemed to have their relevant issues resolved.

In the language above, Staff added the potential for a limited risk component to the language proposed by the PPG. However, Staff's proposal included a restriction on imposing the risk component on two types of Augmentation. Here Staff's proposal overreaches. BPA considers the potential risk component for the reallocation to the Augmentations an important factor in designing an overall balance between BPA's power purchase costs and surplus sales costs. Therefore, the potential to apply a risk component on reallocations to the Augmentations should be reinstated. Therefore, the last sentence in the paragraph above will read:

In the event such power is not reallocated to another Tier 2 Cost Pool, ~~to Augmentation for Initial CHWM or to Augmentation for Additional CHWM~~, BPA may include a risk component or adjustment mechanism for the risk associated with the potential difference between forecast and actual market prices.

BPA believes that this modification does not impinge on the resolution of the issue raised by the PPG. Thus, BPA believes the revised language would also resolve the PPG issue.

Decision

BPA adopts the section 3.4 language agreed to in settlement discussions, as entered in BPA's motion, TRM-12-M-BPA-11, Attachment A, with the modification discussed above.

3.6 The Shared Rate Plan

Issue

Whether BPA should establish a "cap" on the level of Shared Rate Plan (SRP) service that may be offered.

Parties' Positions

NRU suggests that BPA should consider removing the "cap" on the level of initial participation in the SRP. NRU Brief, TRM-12-B-NR-01, at 3.

BPA Staff's Position

A cap on the level of initial participation in the SRP is necessary. Cherry *et al.*, TRM-12-E-BPA-02, at 23-24; Cherry *et al.*, TRM-23-E-BPA-10, at 7. Without a participation limit, the SRP could mask actual incremental costs and thus mask the important price signals that will encourage regional infrastructure, particularly conservation. Cherry *et al.*, TRM-12-E-BPA-02, at 23.

Evaluation of Positions

NRU suggests that BPA remove the cap on SRP participation and reserve the right to impose a cap at a future date if initial interest in the program exceeds expectations. NRU Brief, TRM-12-B-NR-01, at 3. Staff considered this option during the course of the proceeding but concluded that proposing a cap on initial SRP participation is necessary. Staff did, however, respond to parties' concerns by proposing to raise the cap from 500 aMW to 700 aMW. Cherry *et al.*, TRM-12-E-BPA-10, at 7.

Staff's proposed increase in the cap addresses some of the NRU's concerns about limiting participation in the SRP. While BPA is increasing the level of participation by 200 aMW, this limited increase will not compromise BPA's RD Policy goal of sending price signals through the tiering of rates. BPA has stated for some time that a limit on the level of participation is necessary. Ultimately, as stated in testimony, "[w]ithout a limit, the SRP could subvert the general concept of tiered rates because the SRP melds the costs of new Federal resources with the costs of the existing Federal system and shares these costs within a customer pool." Cherry *et al.*, TRM-12-E-BPA-02, at 23. By melding costs of new resources with the anticipated lower costs of the Tier 1 System Resources, the SRP will mask the actual incremental costs associated with the new resources. *Id.* By limiting participation in the SRP to Load Following customers

that place their entire load on BPA, price signals from tiered rates would have a significantly smaller impact on the purchasing and infrastructure decisions of these utilities.

NRU's proposal to remove the cap on the participation level and then somehow impose one at a later date if interest in the program exceeds some undefined level leaves unanswered a number of difficult questions. First, NRU fails to explain what the trigger point would be to impose a cap. Second, there is no explanation of how BPA would then allocate among the interested utilities the capped amount. Even assuming that these questions were answered satisfactorily, NRU's proposal undermines the policy objective behind tiered rates. Staff was willing to increase the level of participation in the program because it was perceived that this limited increase kept the program to less than 10 percent of the total expected CHWMs. Cherry, *et al.*, TRM-12-E-BPA-10, at 7. This fact, coupled with the fact that the program was limited to Load Following customers that place 100 percent of their load on BPA, meant that the objective behind tiering the rates would not be lost. NRU's proposal to essentially uncap the level of participation at the outset, if implemented, would undermine this objective.

Decision

BPA adopts a cap of 700 aMW for initial participation in the Shared Rate Plan.

3.7 Resource Support Services and Resource Shaping Charge

Issue

Whether the general pricing approach behind the Diurnal Flattening Service (DFS) and the application of the Resource Shaping Charge (RSC) is appropriate.

Parties' Positions

With regard to service charges for Non-Federal Resources and the Resource Shaping Charge, WPAG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, and GP, states that BPA has lost sight of the larger objective of providing preference customers the maximum amount of Tier 1 service from the FBS at the embedded cost of those resources. WPAG Brief, TRM-12-B-WA-01, at 11-12; Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; Canby Joinder, TRM-12-M-CA-01; GP Joinder, TRM-12-M-GP-05. WPAG claims that BPA has permitted the desire to provide "price signals" to trump the objective of securing for preference customers Tier 1 service at cost. WPAG Brief, TRM-12-B-WA-01, at 9-10.

BPA Staff's Position

The intent of the DFS, in conjunction with the RSC, is to reflect the fact that variable resources add to the uncertainty of BPA's load obligation for its Load Following customers and the fact that resources change the net load that BPA serves. Cherry, *et al.*, TRM-12-E-BPA-06, at 10.

New resources added to serve new load must not be subsidized by Tier 1 Rates. Fisher, *et al.*, TRM-12-E-BPA-06, at 40.

The DFS is a service that would make a variable or intermittent resource, or that portion of the resource output that is variable or intermittent, financially equivalent to a resource that is flat within the 24 Monthly/Diurnal periods of the year. Fisher, *et al.*, TRM-12-E-BPA-06, at 39. This service would allow resources that have output variations (due to natural variations rather than dispatch decisions) within the Monthly/Diurnal periods of the year to align with the Tier 1 rate design (through the Resource Shaping Charge), which establishes 24 Monthly/Diurnal Load Shaping rates. DFS would also ensure that a resource provides sufficient capacity to meet BPA's flat annual benchmark for above-RHWM loads. *Id.*

The RSC is a customer-specific annual charge or credit that would adjust for the difference in value between a planned resource energy shape that is flat within each of the 24 Monthly/Diurnal periods of the year and an equivalently sized flat annual block. Fisher, *et al.*, TRM-12-E-BPA-06, at 48.

Evaluation of Positions

WPAG states that Staff's proposed pricing methodology behind the RSC and the DFS has lost sight of the larger objective of providing preference customers the maximum amount of Tier 1 service from the FBS at the embedded cost of those resources. WPAG Brief, TRM-12-B-WA-01, at 11. WPAG connects its DFS and RSC arguments to the preference customers' not seeking perfect symmetry between service to preference customer loads and market revenues from secondary sales. *Id.*

DFS and RSC allow a utility to choose to meet its own load growth with new resources that have little or no firm capacity, that operate unpredictably and intermittently, and that have a wide variety of shapes of output over the year. BPA does not require the utility to convert such resources into resources that can be used to reliably meet firm loads by acquiring capacity, firming up the energy, and reshaping the output. Instead, BPA offers customers the option of BPA doing this for them. DFS and RSC are the charges for doing so.

As with the two other rate design issues (sections 3.4.1 and 3.4.2), WPAG does not articulate whether it was challenging BPA's legal authority to price the DFS and RSC using a marginal cost basis or the policy decision to do so. Because WPAG argues that Staff failed to present evidence that there is no FBS available to provide this service, it would appear that WPAG's concern is a legal one as opposed to a policy decision. Nevertheless, this ROD will evaluate WPAG's argument from both perspectives.

Because no party raised this issue during the evidentiary portion of the proceeding, Staff did not address the issue raised by WPAG. While there is no evidence in the record regarding the availability of the FBS to provide this service, that issue is secondary to a more fundamental question; namely, whether it is appropriate for BPA to price products and services using a marginal cost-based pricing construct, irrespective of whether BPA has FBS resources available

to provide the product or service. As noted in sections 3.4.1 and 3.4.2, BPA has the authority to include marginal cost-based price signals in its rate design.

To the extent that WPAG seeks to challenge the policy decision to send customers price signals with the DFS and the RSC, Staff states in testimony the cost causation principle related to the design of the DFS and the RSC. The objective of the DFS pricing methodology is to approximate the market cost of providing a resource flattening service to help ensure that the power sold at Tier 1 Rates does not subsidize power sold at Tier 2 Rates. Fisher, *et al.*, TRM-12-E-BPA-06, at 40. Subsidization, from a tiered rates perspective, would otherwise occur because resources used to serve Above-RHWM Load would be using the flexibility of the Tier 1 System without full compensation. Setting the rate for DFS at a marginal cost would also encourage the development of a market for this type of service. *Id.* DFS price signals should also lead to innovation and investment in new technologies that would allow entities to provide the service at a lower cost. *Id.* The demands placed on the existing Federal system are expected to increase in the future. *Id.* This may force BPA to acquire additional resources in order to provide the capacity and the flexibility required by the DFS. *Id.* By approximating the cost of providing this service using the costs of new capacity resources would avoid the cost spikes and consequent rate shocks that may occur if BPA's existing infrastructure could no longer meet the capacity needs of customers. *Id.*

One of BPA's policy objectives is to ensure that BPA does not use the Tier 1 System in a way that creates an advantage for the Tier 2 Rates. RD Policy at 22. To accomplish this, the TRM provides that BPA's Tier 2 Rates will include the same costs as are reflected in the RSC and DFS services for customers' own resources. If instead BPA were to include anything less than marginal costs in the DFS and RSC charges and in its Tier 2 Rates, the fundamental principle of not subsidizing Tier 2 Rates with Tier 1 would be violated. Alternatively, if BPA were to price RSC and DFS for customers' own resources at less than full marginal cost and price the comparable services included in power to be sold at Tier 2 Rates at full marginal cost, then the customers' choice between acquiring their own resources vs. BPA Tier 2 would be biased against BPA Tier 2.

Because BPA serves the net requirement of its Load Following customers, the Load Following product has always had the challenge of ensuring that Non-Federal Resources serving Load Following customer loads do not create a cost shift or an arbitrage situation. For this reason, contractual resource obligations that require non-BPA resource support for Load Following customers are not new to BPA. For example, under the current Subscription contracts, several customers hire third-party providers to allow them to meet their contractual resource obligations, a service for which they pay a non-FBS related rate. Staff created this same parity under the proposed TRM by creating an economic benchmark (flat annual block) for serving Above-RHWM Load. This benchmark also created the transparent comparability between Tier 2 Rate Alternatives and Non-Federal Resources. As BPA Staff testified,

To create a basis for parity and comparison among the customer's options on how to serve its above-RHWM load, BPA would sell all power at Tier 2 rates as if it were a flat annual block of energy. This flat annual block would create an economic benchmark to allow comparison among Tier 2 Rate Alternatives and

Non-Federal Resources that a customer could choose to serve above-RHWM load. Basing the price of Tier 2 Rate Alternatives on a supply of power shaped in a flat annual block is straightforward and would also reduce BPA's administrative burden. The flat annual block should avoid future cost disputes and disagreements that could arise under a variably shaped Tier 2 Rate designs.

Cherry, *et al.*, TRM-12-E-BPA-02, at 10.

The RSC and the LSC provide effectively similar services, with one applied to a resource and the other to load. The LSC is the charge for BPA shaping the Firm Critical Output of the Tier 1 System Resources to a customer's Actual Tier 1 Load. The RSC is the charge for BPA shaping a Monthly/Diurnal flat resource into a flat annual block. Fisher *et al.*, TRM-12-E-BPA-06, at 49. Because the RSC effectively mirrors the LSC, the issue regarding the LSC that was addressed in section 3.4.2 *supra* is equally applicable to the RSC; that discussion will not be repeated here.

Ultimately, the RSC could have been replaced by the LSC without changing the amount of the effective bill. Staff proposed a separate RSC because of the desire to transparently show cost or benefit of different resource shapes. The cost or benefit of different resource shapes should be transparent. If BPA folded the seasonal costs of the resource into the rates applied to loads, then this transparency would be lost. Also, BPA would price the power sold at a Tier 2 Rate as if it was delivered in flat annual blocks. BPA would apply the same RSC to resources whose costs are allocated to Tier 2 Cost Pools, thus making the seasonal benefits or costs of a resource transparent in BPA's Tier 2 Rates. Applying this transparency to Non-Federal Resources also would provide consistency and comparability. *Id.* To avoid biasing customers' choices, BPA's charges for non-transmission integration services for Non-Federal Resources will be the same as those included in Tier 2 Rates based on similar resources. RD Policy at 21.

Further, the DFS and the RSC are major components of keeping the costs of serving Above-RHWM Loads from migrating into Tier 1 Rates. Without the DFS and the RSC, a customer or BPA could purchase a resource that has a costly shape and have that cost subsidized by use of Tier 1 System Resources. The separation of existing (Tier 1) and new (Tier 2) resource costs is a major concern of WPAG, *id.* at 18; WPAG offers no suggestion as to how it reconciles its concerns for the separation of costs with its position on the DFS and RSC.

Decision

The general pricing approach behind the DFS and the application of the RSC are appropriate. The design of the RSC is consistent with that of the LSC and provides added transparency between Tier 2 Rates and Non-Federal Resources. The TRM's pricing methodology for the DFS is consistent with the tiered rates principle that Tier 1 and Tier 2 costs will be kept separate.

3.8 Cost Verification Process for the Slice True-Up Adjustment Charge

Staff proposes to conduct a Cost Verification Process for the Slice True-Up Adjustment Charge that would permit Slice customers and other interested customers to assess whether BPA has

correctly calculated the amount of each expense or revenue credit subject to the Slice True-Up Adjustment. The Cost Verification Process for the Slice True-Up Adjustment Charge would also assess whether the final Slice True-Up Adjustment contains only those expenses and revenue credits permitted to be included and does not contain any that should otherwise be excluded. In TRM settlement discussions with customers, Staff developed the details about the nature and substance of the proposed Cost Verification Process for the Slice True-Up Adjustment Charge. These details are contained in Attachment A of the TRM.

Issue 1

Whether BPA should modify sections 1c and 4d of Attachment A consistent with the PPG proposal.

Parties' Positions

The PPG, joined by Clatskanie, EWEB, Central Lincoln PUD, Canby Utility Board, Cowlitz PUD, and Grays Harbor PUD, proposed changes to the language in section 1c and section 4d of Attachment A of the TRM, Cost Verification Process for Slice True-Up Adjustment Charge. PPG Brief, TRM-12-B-PPG-01, at 18-19; Clatskanie Joinder, TRM-12-M-CK-02; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Canby Joinder, TRM-12-M-CA-01; Cowlitz Joinder, TRM-12-M-CO-01; Grays Harbor Joinder, TRM-12-M-GH-01. Snohomish supports the PPG proposal, but with one modification. Snohomish Brief, TRM-12-B-SN-01, at 8. Snohomish's proposed modification is addressed separately in Issue 3 below. The PPG states that adoption of its proposed language would resolve all of the PPG's issues related to the Attachment A of the TRM. PPG Brief, TRM-12-B-PPG-01, at 18.

The following is the PPG's proposed modification to sections 1c and 4d of Attachment A:

Section 1c

...however, BPA may exclude any requested additional task that BPA reasonably determines: 1) is without merit; 2) or would be immaterial to the calculation of the Slice True-Up Adjustment; 3) or is a matters outside the scope of the Slice True-Up calculations as provided in section 1a; or 4) matters that concern challenges an issue that should be finally determined in a 7(i) Process because it regards the appropriate allocation between Slice and non-Slice customers previously determined in a 7(i) Process.

Section 4d

Any issue raised pursuant to section 4b above will be forwarded to the neutral third party for non-binding review unless BPA reasonably determines that such issue is inappropriate for third-party non-binding review because it concerns: 1) the allocation of a New Expense; 2) matters that are immaterial to the calculation of the Slice True-Up Adjustment; or 3) matters that are outside the scope of the cost verification process for the Slice True-Up Adjustment as set forth in section 1a above.

PPG Brief, TRM-12-B-PPG-01, at 18-19.

BPA Staff's Position

In BPA's October 7, 2008, Motion to Supplement the Record and Allow for Comment, Staff proposed to modify sections 1c and 4d of Attachment A consistent with the PPG's proposal. BPA Motion, TRM-12-M-BPA-11, Attachment A. The modifications to these sections of Attachment A are intended to provide additional clarity. In particular, the modifications are intended to clarify that any one of the four exceptions may be used by BPA to exclude a matter from the AUP process under section 1c and from the non-binding review under section 4d.

Evaluation of Positions

In its October 14, 2008, Motion Submitting Comments Regarding BPA Motion to Supplement the Record, the PPG accepts the language that BPA submitted in its Motion to Supplement the Record. PPG Motion, TRM-12-M-PPG-04, at 2. As a consequence of the decision to adopt this modification, the PPG deems resolved the issues addressed in its brief regarding Attachment A. Thus, all those joining with the PPG are deemed to have their relevant issues resolved.

Decision

BPA adopts the language of sections 1c and 4d from Attachment A consistent with the PPG proposal.

Issue 2

Whether BPA should continue to provide the same audit rights to Slice customers as provided for in current Slice contracts.

Parties' Positions

Snohomish, joined by EWEB, Central Lincoln PUD, and Grays Harbor PUD, states that while the annual "cost true-up" provided for under the Slice contract offers significant risk mitigation risk for BPA, it imposes a correspondingly significant risk upon the Slice customer. Snohomish Brief, TRM-12-B-SN-01, at 5; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Grays Harbor Joinder, TRM-12-M-GH-01. Snohomish also states that when negotiating the original Slice agreement, BPA and Slice customers recognized the need to mitigate the financial risk placed on the Slice customer and adopted audit procedures to ensure that annual cost true-ups were properly calculated. Snohomish Brief, TRM-12-B-SN-01, at 5. Snohomish concludes that since the current Slice product continues to bear significant risk, the TRM should incorporate the same audit provisions found in the current Slice agreement. *Id.*

BPA Staff's Position

BPA Staff believes, and has believed from the outset of developing the TRM, that there is a need to have a single forum for verifying that BPA has properly allocated costs and credits between Slice and non-Slice rates, and between Tier 1 and Tier 2 rates. This single forum for verification is necessary because of fundamental changes in conditions that will exist in the post-FY 2011 period. This single forum will be different from the current Slice audit that exists today, because Slice and non-Slice rates will be more closely related under the TRM than they are under the prior rate design.

In its initial proposal, Staff proposed that a cost verification process would replace the Slice audit that is provided for in the existing Slice contract and Slice Settlement Agreement. Cherry, *et al.*, TRM-12-E-BPA-02, at 22. If there were disputes related to the allocation of the costs to Slice customers, any adjustments resulting from a dispute would be reserved for the next general 7(i) Process. *Id.* Staff proposed that the details of this verification process would be developed in future relevant 7(i) Processes and included in BPA's General Rate Schedule Provisions. Lovell, *et al.*, TRM-12-E-BPA-08, at 9. Staff proposed to work with customers to develop the protocols for the verification process to ensure that specific customer concerns are identified and addressed in a collaborative manner. *Id.*

In its supplemental proposal, Staff modified its position regarding the cost verification process being developed in future rate cases, and included in the TRM details of a Cost Verification Process for the Slice True-Up Adjustment Charge (TRM-12-E-BPA-09, Attachment A). Bliven, *et al.*, TRM-12-E-BPA-11, at 4. These details were developed during settlement discussions with parties that occurred after the prehearing conference. *Id.* at 5. Staff moved the provisions for the Cost Verification Process for the Slice True-Up Adjustment Charge into the proposed TRM to address the customers' desire to have certainty with respect to this process. *Id.* at 6.

In its rebuttal testimony, Staff proposed to modify language for the Cost Verification Process for the Slice True-Up Adjustment Charge, consistent with the PPG proposal, which other customers supported. Bliven, *et al.*, TRM-12-E-BPA-16, at 8. The PPG proposed modified language as a remedy to customer concerns regarding BPA's unilateral control over verification issues going forward to the Agreed-Upon Procedures (AUPs) process. *See* PPG Direct Testimony, TRM-12-E-PPG-01, at 23-24.)

In BPA's Motion to Supplement the Record and Allow for Comment, Staff proposed to modify language for the Cost Verification Process for the Slice True-Up Adjustment Charge consistent with the PPG proposal (PPG Brief, TRM-12-B-PPG-01, at 18-19) that is addressed in Issue 1 *supra*. BPA Motion, TRM-12-M-BPA-11.

Evaluation of Positions

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, along with any new costs or credits 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 legitimate customer interests.

After FY 2011, two fundamental differences in conditions would call for a different approach to addressing these legitimate interests of customers. *See* Cherry, *et al.*, TRM-12-E-BPA-02, at 23. First, the new rate design and contracts increase the likelihood that all customers, not just Slice customers, will have a keen interest in ensuring that such post-7(i) Process allocations are done properly. *Id.* Currently, all customers are interested in the allocation between Slice and non-Slice rates. *Id.* Under the TRM, all customers will want to be sure that new costs are correctly allocated between Tier 1 and Tier 2 Cost Pools. *Id.* Many customers will also have an interest in proper allocation of costs among different Tier 2 Cost Pools. *Id.* Second, the days of five-year Rate Periods are very likely gone, and with that change, the frequency of significant new costs appearing in the Slice True-Up will decline, because the time between 7(i) Processes will be shorter. *Id.*

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. *Id.* at 22. BPA believes that forum is more efficiently and logically the relevant 7(i) Processes. 7(i) Processes have not historically "looked backward" at cost allocations in the prior Rate Period, but BPA now proposes that this *ex post* review be added to future cases. *Id.* For Slice, a verification process focused narrowly on the second interest would be appropriate.

To support its conclusion that the TRM should incorporate the same audit provisions found in the current Slice agreement, Snohomish refutes Staff's two justifications for reducing the audit rights Slice customers currently rely upon. Snohomish Brief, TRM-12-B-SN-01, at 6. Snohomish states that Staff's first justification for reducing Slice audit rights is that audit provisions would result in logistical and practical difficulty, because many parties are interested in the treatment of costs and their assignment to various pools. *Id.* Snohomish does not agree with Staff that audit provisions would result in logistical and practical difficulty. Snohomish stated that the cost pools under the current Subscription Contracts and the Cost Pools described in the TRM are largely the same; therefore, allowing for audit provisions for the future Slice product would not be difficult. *Id.* Snohomish states that Staff has offered no concrete evidence of logistical difficulty of conducting future audits under the TRM. *Id.* Snohomish states that preserving the current Slice audit rights but allowing a "broader review" of audit results by customer groups would be a desirable solution, instead of the Cost Verification Process that is described in the TRM. *Id.*

Snohomish states that Staff's second justification for reducing Slice audit rights is that such rights are not typical in BPA contracts. *Id.* Snohomish cited examples of BPA contracts that contain audit provisions. *Id.* at 7. Snohomish asserted that BPA has a history of including audit rights where they are necessary or reasonable. *Id.* Snohomish stated that such audit rights are necessary and reasonable, both for the original Slice contract and for the Regional Dialogue Slice contract. *Id.*

BPA acknowledges that the existing Slice contract provides the Slice customer with a right to audit BPA's annual Slice True-Up Adjustment, and the Slice Settlement Agreement allows a form of dispute resolution if the Slice customers disagree with the assignment of costs to them. *See Cherry et al.*, TRM-12-E-BPA-02, at 22. However, due to fundamental changes in the post-FY 2011 period described above, BPA will replace these contract provisions with TRM provisions for verification of identified costs for the Tier 1 Rates and procedures for resolving disputes over allocation of costs. *Id.*

In recognition of future circumstances in the post-FY 2011 period, Staff worked with TRM parties to develop the proposed Cost Verification Process for the Slice True-Up Adjustment Charge. The Cost Verification Process for the Slice True-Up Adjustment Charge retains the important elements of the current audit process, which include the opportunity to review BPA's Power Services revenues and expenses, obtain relevant additional information from BPA regarding BPA's financial performance, compare BPA's actual costs to its forecast costs, review the assignment of costs among cost categories and cost pools, and track future financial developments. *Bliven, et al.*, TRM-12-E-BPA-11, at 4. In addition, TRM parties may request a third-party non-binding review process for cost verification issues that are in dispute. *Id.* at 5. BPA will decide which issues would be forwarded to the third party for an opinion. *Id.*

After the TRM language was drafted and the additional feature of the third-party non-binding review process was incorporated, Slice Customers, the PPG, and Snohomish were still concerned that the language in Attachment A of the TRM appeared to confer BPA with unilateral and unlimited rights to exclude issues from the AUP process and the third-party non-binding review process. *Helgeson, et al.*, TRM-12-E-SC-01, at 8; PPG Direct Testimony, TRM-12-E-PPG-01, at 21; Miles, TRM-12-E-SN-01, at 5. Staff worked with TRM parties on language to address those concerns. BPA and the TRM parties agreed on language that would be included in Attachment A of the TRM. BPA Motion, TRM-12-M-BPA-11; PPG Motion, TRM-12-M-PPG-04, at 2. The PPG, whose motion on this issue included the Slice Customers and Snohomish, concluded that the language proposed for Attachment A of the TRM represents a fair compromise of the positions of the parties represented in the TRM proceeding. PPG Motion, TRM-12-M-PPG-04, at 2.

Decision

BPA will not continue to provide the same audit rights to Slice customers as provided for in current Slice contracts. BPA adopts the Cost Verification Process for the Slice True-Up Adjustment Charge, as developed in a collaborative process, which provides similar protections as the audit.

Issue 3

Whether BPA should delete the provision that allows BPA to exclude from the AUP process matters that it determines are "without merit."

Parties' Positions

Snohomish, joined by Clatskanie, EWEB, Central Lincoln PUD, and Grays Harbor PUD, states that the PPG's proposed language for section 1c of Attachment A that BPA adopted (*see* Issue 1) still allows BPA to retain the discretion to exclude issues from the AUPs that BPA determines are "without merit." Snohomish Brief, TRM-12-B-SN-01, at 8; Clatskanie Joinder, TRM-12-M-CK-02; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Grays Harbor Joinder, TRM-12-M-GH-01. Snohomish states its concern that this language confers upon BPA extreme, if not unlimited, discretionary power to exclude issues from review in the AUP process and subsequently from the non-binding review by a neutral third party. Snohomish Brief, TRM-12-B-SN-01, at 7. Snohomish states that if BPA chooses to retain the words "without merit," then BPA should clarify that all of the exceptions contained in section 1c of Attachment A, and specifically, the "without merit" exception, will be read narrowly. *Id.* at 8. Snohomish states that it wants assurances that it is not BPA's intent to frustrate the overall goal of properly calculating the Slice True-Up Adjustment Charge. *Id.*

BPA Staff's Position

BPA Staff's stated intent was to give BPA the ability to filter tasks out of the AUPs that "would not efficiently and effectively achieve the goal of verifying that BPA correctly calculated the amount of any expense or revenue credit in the Slice True-Up Adjustment Charge." Bliven, *et al.*, TRM-12-E-BPA-16, at 5. In doing so, Staff's objective was to ensure that the AUP process was timely, efficient, and focused. *Id.*

The proposed language is not intended to give BPA the ability to unilaterally reject meritorious issues, but rather to allow BPA the ability to evaluate the issues raised. *Id.* at 6. This discretion was designed to allow BPA to determine whether the matter was best addressed in the AUPs or in a 7(i) Process. *Id.*

Evaluation of Positions

Snohomish objects to the insertion of the "without merit" exception to the referral of issues for AUP review because, Snohomish states, it gives BPA too much discretion in filtering out issues from the AUP process. Snohomish Brief, TRM-12-B-SN-01, at 8.

The "without merit" provision is one of four criteria that will apply to BPA's screening of issues for the AUP process. The intent behind the language is to allow BPA to exclude from the AUP process issues that are unrelated to the cost in question, unrelated to Slice costs, or are matters on other policy issues before BPA and simply outside the scope of cost review. Bliven, *et al.*, TRM-12-E-BPA-16, at 5. This provision allows BPA and the parties to effectively and efficiently determine whether BPA properly calculated the amount included in the Slice True-Up Adjustment Charge. BPA must have a means of excluding unreasonable and burdensome requests for data that will not ultimately lead to conclusions regarding the appropriate inclusion or exclusion of costs in the Composite Cost Pool.

Snohomish requests that if BPA chooses to retain the words “without merit,” then BPA should provide clarification that all of the exceptions contained in section 1c of Attachment A, and specifically, the “without merit” exception, will be read narrowly and that it is not BPA’s intent to frustrate the overall goal of properly calculating the Slice True-Up Adjustment Charge. Snohomish Brief, TRM-12-B-SN-01, at 8. Staff has provided sufficient clarification of its intent with respect to the language contained in section 1c of Attachment A in its rebuttal testimony. The Staff proposal does not change the intent, which is to implement the Cost Verification Process for the Slice True-Up Adjustment Charge in a fair and transparent way.

Decision

BPA will retain the “without merit” provision. It is important for the AUP process to be efficient and effective and for BPA to have the ability to filter out matters that are not related to the allocation of expenses and revenue credits to the Composite Cost Pool.

3.9 Revising the TRM

The TRM is designed to be a predictable and durable means by which to tier BPA’s PF rate for firm requirements power service. TRM-12-E-BPA-20 at 1. During development of the TRM, Staff and parties to the discussions agreed that the TRM should be revised in the future as little as possible to ensure its predictability and durability. TRM sections 12 and 13 are key components of providing long-term certainty and predictability. Section 12 lists criteria and conditions that must be met for revising the TRM, including actions that are not considered to be a revision to the TRM. Section 13 sets forth the applicable processes for any TRM revisions.

Staff’s initial proposal TRM, TRM-12-E-BPA-01, included the proposed sections 12 and 13 that resulted from discussions with interested parties prior to May 2008. Staff’s direct testimony included an alternative Section 13. Cherry *et al.*, TRM-12-E-BPA-02, Attachment A. In discussions with parties, the language in sections 12 and 13 was revised; discussions on section 13 used Attachment A to TRM-12-E-BPA-02 as a starting point. The results of the discussions to that point were included in the TRM Supplemental Proposal, TRM-12-E-BPA-09. Sections 12 and 13 also carried the caveat that “Sections 12 and 13 in this Supplemental TRM will be proposed for the Administrator’s consideration by Staff only in the event customers uniformly support and do not contest these sections. In that respect, this version of these sections is akin to an offer of settlement.” TRM-12-E-BPA-09, at 91, 96. Sections 12 and 13 were revised again through further discussion among parties prior to rebuttal testimony being filed. TRM-12-E-BPA-20.

Issues regarding revising the TRM pursuant to sections 12 and 13 are discussed below. In addition, Issue 2 in section 1.4 of this ROD discusses near-term revision of the TRM.

Issue 1

Whether sections 12 and 13 of the TRM, when read together, give BPA's existing customers a "veto" over changes to the TRM to the exclusion of public bodies that may be eligible to become New Publics.

Parties' Positions

ATNI argued that sections 12 and 13 of the TRM, when read together, give existing customers a "veto" over changes to the TRM during the 20-year term of the TRM to the exclusion of public bodies that may be eligible to become new publics. ATNI Brief, TRM-12-B-AT-01, at 15. ATNI argued that such a "veto" is an improper delegation of the Administrator's statutory obligations to entities with commercial interests. *Id.* ATNI further argued that Federal antitrust law prohibits the attempt to monopolize or conspire with other persons to monopolize any part of trade or commerce. *Id.* at 16. ATNI argued that the new procedures in sections 12 and 13 create expensive and unduly burdensome processes and timelines that are in addition to the statutory procedures already applicable to BPA ratemaking and that the TRM procedures inappropriately restrict the access of non-customers to the Federal system and Federal processes. *Id.*

BPA Staff's Position

The procedures in section 13 that ATNI complained of do not apply to customers that do not sign CHWM Contracts, including those that desire to be such customers in the future, or interest groups that are not BPA customers. Cherry, *et al.*, TRM-12-E-BPA-15, at 22. The TRM does not alter the rights of a new public seeking to form to raise appropriate rate issues in 7(i) Processes; BPA will decide the issues based on the 7(i) Process record. *Id.* at 22-23. TRM sections 12 and 13 do not limit non-customers' existing procedural protections to either the Federal system or to Federal processes. *Id.* at 23.

Evaluation of Positions

ATNI first raised this issue in its direct case. Staff countered it with the rebuttal testimony summarized above. In its Motion Commenting On TRM Proposed Changes And Identifying Arguments No Longer At Issue, TRM-12-M-AT-03, ATNI indicates that it supports Staff's proposed changes to section 4.1.6.3 set forth in Attachment A of TRM-12-M-BPA-11. (*See* section 3.3.4.) ATNI also indicates in its motion that if those changes are finally approved by the Administrator in this proceeding and other provisions remain unchanged from BPA's current proposal, then the arguments in ATNI's brief, including "Section III. Criteria and conditions for revising the TRM give existing customers a veto and could restrict access to the FRPS by new customers," are no longer at issue. ATNI Motion, TRM-12-M-AT-03, at 1. The Administrator herein adopts the changes requested by ATNI (*see* section 3.3.4); thus, ATNI's concerns with section 12 and 13 are no longer at issue.

Decision

Sections 12 and 13 of the TRM, when read together, do not give BPA’s existing customers a “veto” over changes to the TRM to the exclusion of public bodies that may be eligible to become New Public.

Issue 2

Whether BPA should revise the language in section 13 to expressly indicate that nothing in section 12 or 13 of the TRM precludes an IOU, or other 7(i) Process party that has not signed a CHWM Contract, from proposing a revision to the TRM in a 7(i) Process.

Parties’ Positions

The IOUs expressed concern about proposed changes to TRM section 10.5. IOU Brief, TRM-12-B-JP-01, at 19. The IOUs were particularly concerned in light of the control afforded to Publics in sections 12 and 13 of the Draft TRM. *Id.* The IOUs stated that section 13 did not preclude the IOUs from proposing changes for adoption in a 7(i) Process to establish rates and quoted the TRM:

Nothing in this section 13 1) precludes any party to a BPA 7(i) Process, other than a Customer [a Public that purchases power from BPA at a Tier 1 Rate under a CHWM contract], from making any proposal or offering any testimony or other evidence on any matter that may otherwise be raised in a BPA 7(i) Process or 2) constrains any person or entity from taking any position with BPA on any issue outside of a 7(i) Process.

Id. at 20. The IOUs proposed revising the sentence to read:

Nothing in section 12 or this section 13 1) precludes any party to a BPA 7(i) Process, other than a Customer [a Public that purchases power from BPA at a Tier 1 Rate under a CHWM contract], from making any proposal or offering any testimony or other evidence on any matter that may otherwise be raised in a BPA 7(i) Process or 2) constrains any person or entity from taking any position with BPA on any issue outside of a 7(i) Process.

Id.

BPA Staff’s Position

In its Supplemental Proposal, BPA Staff proposed TRM language to clarify that TRM sections 12 and 13 do not preclude any party to a BPA 7(i) Process other than a Customer (Customer is defined in section 13 as “a Public that purchases power from BPA at a Tier 1 Rate under a CHWM Contract”) from raising any issue in a 7(i) Process. Cherry, *et al.*, TRM-12-E-

BPA-10, at 13. This clarification means that interested 7(i) Process parties, including entities that do not sign CHWM Contracts, may raise any issue for consideration in a 7(i) Process.

Evaluation of Positions

It was not Staff's intent to limit the procedural protections that any party that does not sign a CHWM Contract has in a 7(i) Process. Staff noted in supplemental testimony, "[w]e propose these revisions because we recognize that the TRM is a rate design applicable to only those customers that sign CHWM Contracts. BPA's rate design cannot override section 7(i) procedural rights of customers without a CHWM Contract or limit BPA's broader programmatic and other responsibilities." Cherry, *et al.*, TRM-12-E-BPA-10, at 13.

BPA believes that the language in the TRM is sufficient; however, the language proposed by the IOUs may be clearer to some, so BPA has no objection to adding the reference to section 12 as the IOUs suggested:

Nothing in section 12 or this section 13 1) precludes any party to a BPA 7(i) Process, other than a Customer, from making any proposal or offering any testimony or other evidence on any matter that may otherwise be raised in a BPA 7(i) Process or 2) constrains any person or entity from taking any position with BPA on any issue outside of a 7(i) Process.

Decision

BPA adopts the language in section 13 to expressly indicate that nothing in TRM section 12 or 13 precludes a 7(i) Process party that has not signed a CHWM Contract from proposing a revision to the TRM in a 7(i) Process.

4.0 Residential Exchange Program, Sections 7(b)(2) and 7(b)(3)

4.1 Introduction

The PF Exchange rate applies to BPA's power sales to utilities participating in the Residential Exchange Program. 16 U.S.C. § 839c(c). The difference between BPA's PF Exchange rate and the exchanging utility's average system cost of resources, multiplied by the utility's residential and small farm load, equals the monetary benefits provided to the utility under the REP. While the PF Exchange rate is not being tiered as the PF Preference rate is, the relationships between tiering the rates for preference customers and the rates applicable to the REP have implications for the way preference customers might participate in the REP.

Section 7(b)(2) of the Northwest Power Act directs BPA to conduct, after July 1, 1985, a comparison of the projected amounts BPA will charge its preference and Federal agency customers for their general requirements with the costs of power for the general requirements of those customers if certain assumptions are made. 16 U.S.C. § 839e(b)(2). The effect of this comparison is to protect BPA's preference and Federal agency customers' wholesale firm power rates from certain costs resulting from the provisions of the Northwest Power Act. The rate test can result in a reallocation of costs from the general requirements loads of preference and Federal agency customers to other BPA loads.

4.2 PF Exchange Rate

Issue 1

Whether the TRM appropriately sets forth the manner in which BPA will determine PF Exchange rates during the term of the TRM.

Parties' Positions

Clark noted that the creation of two PF rates with differing resource cost bases paired with two ASC calculations with differing resource cost bases creates the potential for a cost mismatch in determining REP benefits. Clark Brief, TRM-12-B-CC-01-E1, at 3. Clark stated that without additional clarification to the language of the TRM, preference customers entitled to participate in the REP will have no assurance about the design of the PF Exchange rate that will be compared to their ASCs, and no assurance that the resource cost mismatch will not occur. *Id.* at 4. Clark noted that if the design of the PF Exchange rate is not clarified in the TRM, BPA will be requiring preference customers to permanently agree to limit the resource costs that can be included in their ASCs without any assurance that the PF Exchange rate used to determine their REP benefits will contain only the appropriate Tier 1 resource costs. *Id.* at 5.

The PPG, joined by Clatskanie, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, Canby Utility Board, Cowlitz PUD, and Grays Harbor PUD, provided language the PPG claimed would clarify how the PF Exchange rate for customers with and without CHWM Contracts would be constructed under the TRM, as well as how any section 7(b)(3) surcharge would be applied to PF Exchange rates established under the TRM. PPG Brief, TRM-12-B-PPG-01, at 12;

Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-M-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; Canby Joinder, TRM-12-M-CA-01; Cowlitz Joinder, TRM-12-M-CO-01; Grays Harbor Joinder, TRM-12-M-GH-01. The PPG stated that the tiering of the PF Preference rate raises questions about what will be the appropriate PF rate to use when establishing the PF Exchange rate(s) used in determining the REP benefits, given that Staff is proposing to have two differing cost bases for calculating the ASCs for customers with and without CHWM Contracts. PPG Brief, TRM-12-B-PPG-01, at 12. Clark stated that the language proposed in Staff's rebuttal raised significant ambiguities regarding the cost basis of the proposed Tier 1 PF Exchange Rate, as well as to whom the proposed Tier 1 PF Exchange Rate should apply. *Id.* at 14-15.

The IOUs note that the relative levels of the PF Exchange rates for IOUs and for publics with CHWM Contracts may directly affect the relative levels of REP benefits provided to investor-owned utilities and publics. IOU Brief, TRM-12-B-JP-01, at 12. The IOUs contend that the TRM should not specify that there will be a PF Exchange rate for customers that have a CHWM Contract based on costs allocated to the Tier 1 Cost Pools. *Id.* at 12-13. The IOUs stated that their concern arises from the necessity that a PF Exchange rate for customers with a CHWM Contract must be consistent with BPA's ratemaking statutes and not be arbitrary and capricious. *Id.* at 13.

WPAG, joined by Canby Utility Board and GP, contended that the TRM does not contain an explanation of how its resource cost segregation and allocation can be reconciled with the rate directives in sections 7(b)(1) and (2) of the Northwest Power Act, which compel different resource cost allocations, resource cost melding, and rate ceilings. WPAG Brief, TRM-12-B-WA-01, at 6; Canby Joinder, TRM-12-M-CA-01; GP Joinder, TRM-12-M-GP-05. WPAG's issue is addressed in section 2.0, Issue 2, *supra*.

BPA Staff's Position

Notwithstanding the apparent contradiction between the position of the publics to include specific language regarding the PF Preference rate and the position of the IOUs to exclude such language, Staff fundamentally agreed with the parties' positions outlined above.

Evaluation of Positions

Staff met with parties to resolve the language in TRM section 10.5 regarding the PF Exchange rate and reached agreement on alternative language. Based on the alternative language agreed on by parties, most of the parties raising the above-stated issue agree that their concern has been addressed by the proposed language. The proposed language replaces the former section 10.5 in its entirety:

10.5 7(b)(2) Rate Test

10.5.1 PF Exchange Rate for Customers with a CHWM Contract

For customers that have a signed CHWM Contract and a Residential Purchase and Sale (RPS) Agreement and have agreed they will not seek and will not receive residential exchange benefits pursuant to section 5(c) of the Northwest Power Act

other than pursuant to Section IV(G) of BPA's 2008 Average System Cost Methodology or its successor, BPA will establish a PF Exchange rate(s) in each 7(i) Process. Such rate(s) will be set consistent with the Northwest Power Act and subject to TRM sections 10.5.3 and 10.5.4. Such rate(s) will be based on the costs and credits allocated in such 7(i) Process to the Tier 1 Cost Pools, appropriate transmission costs, and appropriate loads. Such rate(s) will not be based on costs and credits allocated in such 7(i) Process to the Tier 2 Cost Pools, other appropriate transmission costs, or Tier 2 loads.

10.5.2 PF Exchange Rate for Customers without a CHWM Contract

For customers that have not signed a CHWM Contract and have signed an RPS Agreement, BPA will establish a PF Exchange rate(s) in each 7(i) Process. Such rate(s) will be set consistent with the Northwest Power Act and subject to TRM sections 10.5.3 and 10.5.4. Such rate(s) will be based on the costs and credits allocated in such rate case to the Tier 1 and Tier 2 Cost Pools, appropriate transmission costs, and appropriate loads.

* * * *

10.5.4 Interaction of Multiple PF Exchange Rates

To the extent that multiple PF Exchange rates affect the net costs of the REP, the cost effect of such multiple rates will be appropriately reflected in the Tier 1 Cost Pool.

TRM-12-M-BPA-11, Attachment A. Section 10.5.3 is discussed *infra*.

Clark states that the alternative TRM language resolves its issues and arguments and that BPA may treat the issues raised in the Clark brief as resolved. Clark Motion, TRM-12-M-CC-03, at 1.

The PPG states that the alternative language generally is a fair compromise of the positions of the parties represented in this proceeding and that the PPG therefore supports revising the TRM. PPG Motion, TRM-12-M-PPG-04, at 2. The PPG states that the relevant issues summarized in its motion are to be considered resolved. *Id.* at 7-8. Thus, all those joining with the PPG are deemed to have issues resolved.

Despite the alternative language, the IOUs continue to advance many of their arguments presented in brief. IOU Motion, TRM-12-M-JP-04, at 1. The IOUs state that the relative levels of the PF Exchange rates for IOUs and for publics with CHWM Contracts may directly affect the relative levels of REP benefits provided to investor-owned utilities and publics. IOU Brief, TRM-12-B-JP-01, at 12. The IOUs state that the TRM should not specify a methodology for allocating any section 7(b)(3) surcharge or otherwise determining PF Exchange rates. *Id.*

BPA understands that the relative levels of REP benefits will be affected by the existence of two PF Exchange rates. This is inherent in the role of the PF Exchange rate in calculating REP benefits. However, the issue of whether to establish two PF Exchange rates is not one of relative REP benefits, but whether each exchanging utility receives the proper level of REP benefits. If a

public customer with a CHWM Contract is not able to include in its ASC future resources it uses to serve Above-RHWM Load, then the PF Exchange rate against which that public exchanges should not include similarly situated BPA resource costs, which are costs allocated to Tier 2 Cost Pools. Notwithstanding whether the TRM specifies a separate PF Exchange rate for publics with a CHWM Contract, BPA agrees that the TRM should not specify a methodology for allocating section 7(b)(3) surcharges. The TRM contains no such specification, and issues regarding the allocation of section 7(b)(3) amounts are reserved for 7(i) Processes that establish the actual rates.

The IOUs contend that the TRM should not specify that there will be a PF Exchange rate for customers that have a CHWM Contract based on costs allocated to the Tier 1 Cost Pools. *Id.* at 12-13. The IOUs state that their concern arises from the requirement that a PF Exchange rate for customers with a CHWM Contract must be consistent with BPA's ratemaking statutes and not be arbitrary and capricious. *Id.* at 13.

BPA agrees that the PF Exchange rate, both for customers that sign CHWM Contracts and for those that do not sign CHWM Contracts, must be consistent with BPA ratemaking statutes. It is important to note, however, that the IOUs' concern regarding the consistency of the PF Exchange rate with BPA ratemaking statutes is premature, because the TRM does not establish the PF Exchange rate for either CHWM Contract signers or any other customer eligible to purchase under the PF Exchange rate. BPA will establish the PF Exchange rate for the Rate Periods beginning in FY 2012 in the applicable future 7(i) Processes. While BPA is not establishing the PF Exchange rate in the TRM, BPA understands that it is nevertheless important to provide some assurance for publics that sign a CHWM Contract that tiering the rates will not erode the REP benefits they would otherwise be eligible to receive based on the cost of their Existing Resources. Section 10.5 is intended to provide that limited assurance for CHWM Contract signers. If the language in TRM section 10.5 regarding a PF Exchange rate for publics with a CHWM Contract were omitted, eligible publics would have no certainty regarding their continued access to an appropriate level of REP benefits. BPA believes that the language in section 10.5 is a careful compromise between giving publics with a CHWM Contract some certainty regarding continued access to REP benefits for their Existing Resources without specifying other issues regarding the establishment of the PF Exchange rate. Through the language in section 10.5, BPA has committed to establish a PF Exchange rate for publics with a CHWM Contract that excludes costs allocated to Tier 2 Cost Pools while not encroaching on other issues that are reserved for the 7(i) Processes that will establish the actual PF Exchange rates.

The IOUs later state that should BPA include in the TRM a PF Exchange rate for publics with a CHWM Contract, BPA should do so only if the ASC of each such customer is limited to costs of Tier 1 purchases and the costs of other purchases and resources used to meet its existing retail load and specifically not include the cost of resources to serve load growth. *Id.* at 13-14.

BPA agrees with the IOUs' basic premise regarding the eligibility for the PF Exchange rate that will exclude costs allocated to Tier 2 Cost Pools. When BPA proposes to establish specific PF Exchange rates, the eligibility requirements for the Tier 1 PF Exchange rate will be proposed to be structured to limit its availability in a manner consistent with the IOU position.

The IOUs raise further concern regarding the allocation of section 7(b)(3) amounts among REP participants, citing direct testimony of publics raising the concern that the allocation of section 7(b)(3) amounts could result in a disparate distribution of cost responsibility. *Id.* at 14, quoting TRM-12-HOO-14-AT2, at 7. The IOUs contend that the publics' assertion should not and cannot change the scope of the TRM. IOU Brief, TRM-12-B-JP-01, at 14.

BPA concurs with the IOUs. While BPA believes that the section 7(b)(3) allocation methodology adopted in the WP-07 supplemental rate proceeding appropriately addresses the issues raised by publics in their testimony, as cited by the IOUs, such issues are properly reserved by the TRM to the applicable 7(i) Processes that will determine the actual PF Exchange rates.

Decision

The alternative TRM language, as agreed upon by parties, regarding the manner in which BPA will determine PF Exchange rates during the term of the TRM effectively addresses the issues raised. BPA agrees with the alternative language and will include this language in the TRM. While the agreed-upon language commits BPA to exclude certain costs when establishing a PF Exchange rate for publics with a CHWM Contract, the TRM does not otherwise decide issues related to the overall determination of the PF Exchange rates.

4.3 Section 7(b)(2) Rate Test

Issue 1

Whether the scope of the TRM conflicts with statutory directives regarding the section 7(b)(2) rate test.

Parties' Positions

The IOUs state that the TRM should be clarified to expressly indicate that the TRM does not preclude the allocation of section 7(b)(2) trigger amounts to BPA surplus sales, including secondary energy sales under the Slice product. IOU Brief, TRM-12-B-JP-01, at 4-5. The IOUs note that the TRM should not dictate a methodology for allocating any section 7(b)(2) trigger amount (sometimes referred to as a section 7(b)(3) surcharge) or otherwise dictate a methodology for establishing PF Exchange rates. *Id.* at 9.

BPA Staff's Position

BPA Staff expressly intend that the TRM not mandate or pre-condition any aspect of the implementation of Northwest Power Act sections 7(b)(2) or 7(b)(3).

Evaluation of Positions

Staff met with parties to resolve the language in TRM section 10.5 regarding the section 7(b)(2) rate test and reached agreement on alternative language to be proposed in the TRM.

10.5.3 7(b)(2) or 7(b)(3) Issues Not Addressed by TRM

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

Based on the alternative language agreed on by parties, the IOUs agree that their concern is now resolved by the proposed language. The IOUs state that they support the alternative language reflected in TRM section 10.5.3 and their arguments are no longer at issue. IOU Motion, TRM-12-M-JP-04, at 2.

BPA believes that the “Notwithstanding” clause was intended to apply to both sentences in the paragraph. Therefore, the proposed language will be clarified to specify the “Notwithstanding” clause in both sentences.

10.5.3 7(b)(2) or 7(b)(3) Issues Not Addressed by TRM

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

Decision

The alternative language in TRM section 10.5.3 regarding sections 7(b)(2) and 7(b)(3) issues not addressed by the TRM, as agreed upon by parties, effectively addresses the issues raised. BPA agrees with the alternative language and will include this language, modified as discussed above, in the TRM.

5.0 DSI Rate Issues

Issue 1

Whether the Northwest Power Act obligates BPA to provide the DSIs with physical power at a cost-based rate through contracts to meet their power requirements.

Parties' Positions

Alcoa states that the Northwest Power Act gives the DSIs a right to physical power at a cost-based rate. Alcoa Brief, TRM-12-B-AL-01, at 3. Alcoa further argues that BPA has an obligation to provide its DSI customers with contracts to meet their power requirements. *Id.* at 5.

BPA Staff's Position

Staff has not taken a position on this issue in this proceeding; however, BPA has directly addressed this issue in unrelated litigation before the Ninth Circuit. BPA's legal position is set forth in the evaluation below.

Evaluation of Positions

Alcoa raised this issue before the Ninth Circuit in *Pacific Northwest Generating Cooperative, et al. v. BPA*, No. 05-75638. That case has been fully briefed, argued, and submitted to the Court for decision. Accordingly, the issue has not been a subject of this TRM proceeding and, moreover, is not germane to the TRM. BPA relies on its brief and oral argument presented in that case and will not re-argue its position here, except in summary fashion.

The only service BPA was required to offer the DSIs was the initial set of 1981 contracts. After those initial contracts expired, BPA retained the *authority* but not the *obligation* to serve the DSI loads. The Ninth Circuit plainly held in *M-S-R* that “16 U.S.C. § 839c(d) *authorized but did not obligate* BPA to sell the DSIs any power...” *M-S-R Public Power Agency v. BPA*, 297 F.3d 833, 838 (9th Cir. 2007) (*M-S-R*) (emphasis added). This directly aligns with the legislative history of the Northwest Power Act, which states: “Section 5(d) authorizes the Administrator to sell power to existing direct service industrial customers that have a BPA contract at the date this bill is enacted... *Subsequent contracts for these DSI's are authorized but not mandated.*” H.R. Rep. No. 96-976, Part 1, 96th Cong. 2d Sess., 61 (1980) (emphasis added). Accordingly, BPA may contract with the DSIs to sell them power but is not required to do so.

Decision

The Northwest Power Act does not obligate BPA to provide the DSIs with physical power at a cost-based rate through contracts to meet their power requirements.

Issue 2

Whether the Northwest Power Act obligates BPA to acquire sufficient power to provide the DSIs with physical power at cost-based rates.

Parties' Positions

Alcoa argues that BPA is not excused from providing physical power to the DSIs when BPA fails to fulfill its statutory mandate to acquire replacement resources. Alcoa Brief, TRM-12-B-AL-01, at 5. Alcoa states that the text, structure, and legislative history of the Northwest Power Act all indicate that BPA must acquire power sufficient to provide DSIs with physical power necessary to meet their loads and to sell such power at cost-based rates. *Id.* at 5-6. In support of this overall notion, Alcoa discusses Northwest Power Act sections 6(a)(2) and 5(d), the Act's legislative history, BPA's contemporaneous understanding of the Act, the idea that the DSIs supported the Act as a compromise, and the Act "read as a whole." *Id.* at 4-10.

BPA Staff's Position

BPA Staff has not taken a position on this issue in this proceeding; however, BPA has directly addressed this issue in unrelated litigation before the Ninth Circuit. BPA's legal position is set forth in the evaluation below.

Evaluation of Positions

Alcoa raised this issue, and advanced all the same arguments, before the Ninth Circuit in *Pacific Northwest Generating Cooperative, et al. v. BPA*, No. 05-75638. That case has been fully briefed, argued, and submitted to the Court for decision. Accordingly, the issue has not been a subject of this TRM proceeding and, moreover, is not germane to the TRM. BPA relies on its brief and oral argument presented in that case and will not re-argue its position here, except in summary fashion.

Section 6(a)(2)(A) directs the Administrator only to acquire "sufficient resources ... to meet his contractual obligations." 16 U.S.C. § 839d(a)(2)(A). Alcoa has put the cart before the horse. Absent a contractual obligation to make physical deliveries of power, the Administrator has no obligation to acquire resources to meet such contractual obligation. The Ninth Circuit has already held in M-S-R that "16 U.S.C. § 839c(d) *authorized but did not obligate* BPA to sell the DSIs any power" M-S-R at 838. Accordingly, BPA may contract with the DSIs to sell them power but does not have to do so. Only upon entering into a contract to serve the DSIs with physical power does BPA have an obligation to acquire resources to meet that contract.

Alcoa next argues that Congress's use of the word "initial" in section 5(d) of the Northwest Power Act to describe the contracts offered to the DSIs denotes a series. Alcoa Brief, TRM-12-B-AL-01, at 6-7. That is, that there would necessarily be follow-up contracts, which were also mandatory. Contrary to Alcoa's suggestion, the reason Congress included the word "initial" was to distinguish the first contracts, which were mandatory, from later contracts, which were discretionary. Thus, Congress accurately used the word "initial" because it encompassed both

the *requirement* to offer the first contracts to the DSIs and the Northwest Power Act's allowance for the *possibility* that BPA would continue to offer contracts in the future.

Next, Alcoa argues that the legislative history of the Northwest Power Act confirms that Congress intended that BPA serve the DSIs at cost-based rates without a time limitation. Alcoa Brief, TRM-12-B-AL-01, at 7-8. Alcoa fails to address the most directly relevant portion of the legislative history, which expressly provides that section 5(d) authorizes, but does not mandate, power sales to the DSIs after the expiration of their initial contracts: "Section 5(d) authorizes the Administrator to sell power to existing direct service industrial customers that have a BPA contract at the date this bill is enacted... *Subsequent contracts for these DSI's are authorized but not mandated.*" H.R. Rep. No. 96-976, Part I, 96th Cong., 2d Sess. 61 (1980) (emphasis added). Alcoa continues its argument by referencing a BPA interpretation of section 5(d) that was made soon after passage of the Northwest Power Act. Alcoa Brief, TRM-12-B-AL-01, at 7-8. BPA's contemporaneous interpretation of section 5(d) of the Northwest Power Act is in accord with the legislative history. The letter contemplated the possibility of future contracts because BPA recognized then, as it does now, that BPA is authorized but not required to enter into subsequent contracts with the DSIs. *See*, Alcoa Inc.'s Motion to Supplement the Record, TRM-12-M-AL-03.

Next, Alcoa suggests that the DSIs agreed to support the Northwest Power Act as a compromise whereby they would pay for the residential exchange for the first five years in exchange for BPA's ongoing duty to serve them. Alcoa Brief, TRM-12-B-AL-01, at 8-9. Alcoa vastly overstates the *quid pro quo*. The DSIs were given the benefits of 20-year initial power sales contracts along with the *possibility* of subsequent contracts upon expiration of the initial contracts. In addition, Congress directed BPA to replace a then-existing contractual provision that had allowed interruption of 25 percent of the DSIs' load "at any time," with a provision allowing such interruption only when necessary to protect BPA's firm loads. *See Alcoa*, 467 U.S. at 385-87. These were the rewards the DSIs reaped for their contribution to the residential exchange, not the promise of an ongoing duty to serve them.

Next, Alcoa contends that when the Northwest Power Act is read as a whole it shows Congress's intent that BPA should provide the DSIs physical power without a time limit. Alcoa Brief, TRM-12-B-AL-01, at 9-10. In a series of bullet points Alcoa argues, in effect, that the mere mention of DSIs in various sections of the Northwest Power Act means that Congress intended BPA to provide physically delivered power to the DSIs at cost-based rates in perpetuity. *Id.* The premise of this argument is completely flawed. Given that the plain language of the Northwest Power Act demonstrates that BPA has no obligation to sell power to the DSIs *at all* after the initial contracts expired, Alcoa's various arguments about the overall structure of the Northwest Power Act are immaterial and offer no support for Alcoa's contention. BPA's brief in *Pacific Northwest Generating Cooperative, et al. v. BPA*, No. 05-75638, thoroughly addresses and refutes each of the bullet point arguments Alcoa has raised here. BPA relies on its brief and oral argument in that case and will not repeat its arguments here.

Decision

The Northwest Power Act does not obligate BPA to acquire sufficient power to provide the DSIs with physical power at cost-based rates.

Issue 3

Whether the Regional Preference Act requires that BPA offer the DSIs power at cost before selling it outside the region.

Parties' Positions

Alcoa states that the Regional Preference Act expressly requires that BPA offer the DSIs power at cost before selling it outside the Northwest. Alcoa Brief, TRM-12-B-AL-01, at 11-18.

BPA Staff's Position

BPA Staff has not taken a position on this issue in this proceeding; however, BPA has directly addressed this issue in unrelated litigation before the Ninth Circuit. BPA's legal position is set forth in the evaluation below.

Evaluation of Positions

Alcoa raised this argument before the Ninth Circuit in *Pacific Northwest Generating Cooperative, et al. v. BPA*, No. 05-75638. That case has been fully briefed, argued, and submitted to the Court for decision. Accordingly, the issue has not been a subject of this TRM proceeding and, moreover, is not germane to the TRM. BPA relies on its brief and oral argument presented in that case and will not re-argue its position here, except in summary fashion.

Alcoa is effectively arguing that the Regional Preference Act grants the DSIs not only a preference to power but also a preference to price. The Ninth Circuit has consistently held that a preference to power does not equate with or extend to a preference to price. *Central Lincoln People's Util. Dist. v. Johnson*, 735 F.2d 1101, 1125 (9th Cir. 1984) (as amended on denial of rehearing and rehearing *en banc*) (stating that the Northwest Power Act "couches the preference in terms of 'power sales,' not price."); *Trinity County Pub. Util. Dist. v. Harrington*, 781 F.2d 163, 166 (9th Cir. 1986) (allocation does not result in "a preferential rate in addition to a preferential power allocation"); *Kaiser Aluminum & Chemical Corporation, v. BPA*, 261 F.3d 843, 851 (9th Cir. 2001) (*Kaiser*) (regional power preference does not provide price preference). Indeed, even though public preference was created over 70 years ago, there are *no cases* holding that there is a preference to price.

As for the requirements of the Regional Preference Act, it specifies only that BPA offer surplus power at the rate "established" for such sales. Assuming the DSIs can be considered a regional customer, BPA need only offer surplus power to the DSIs at the rate established for such sales. That rate may or may not be BPA's lowest cost-based rate. In accordance with sections 1(c) of

the Regional Preference Act and 9(c) of the Northwest Power Act, the only rate currently established for the sale of surplus power is the FPS-07 rate. Thus, the DSIs have no right under the Regional Preference Act to a delivery of physical power at a rate other than the rate established for the sale of such power, the FPS-07 rate.

The Ninth Circuit has already directly ruled against the arguments Alcoa is raising with regard to the Regional Preference Act. In *Kaiser*, 261 F.3d at 851, Kaiser Aluminum argued that BPA's decision to sell surplus power to the DSIs at the FPS rate schedule rather than at the lower cost-based IP rate violated regional preference. *Kaiser*, 261 F.3d at 850-51. The Court upheld BPA's decision and found that BPA properly applied the FPS rate schedule, which was the only established rate for the disposition of surplus energy. *Id.* Additionally, the Court found that the DSIs had no preference to price and denied the petition for review. *Id.* In all material respects, *Kaiser* is dispositive of Alcoa's claims.

Alcoa cites excerpts from the legislative history of the Regional Preference Act, attempts to draw support from the Northwest Power Act and Excess Federal Power Act, and repeats its arguments regarding the text and history of the Regional Preference Act. Alcoa Brief, TRM-12-B-AL-01, at 11-13. None of these arguments alters the overarching fact that the DSIs have no right under the Regional Preference Act to a delivery of physical power at a rate other than the rate established for the sale of such power, the FPS-07 rate, and that the Ninth Circuit has already directly ruled against the arguments Alcoa is raising. *Kaiser*, 261 F.3d at 851.

Decision

The Regional Preference Act does not require that BPA offer the DSIs power at cost before selling it outside the region.

Issue 4

Whether the TRM should be clarified so that it cannot be interpreted to prevent FBS replacement purchases to serve the DSIs, including up to the level of the Federal Base System.

Parties' Positions

Alcoa states that BPA must clarify in the TRM that the TRM does not eliminate BPA's past practice of purchasing replacement FBS or other resources to serve the DSIs and to recover the costs of doing so by including the cost of the resources in the PF rate to which a "typical margin" is added. Alcoa Brief, TRM-12-B-AL-01, at 19-20. Alcoa states its concern about the changes to the definition of augmentation in the Supplemental TRM to exclude purchases made for the DSIs. *Id.* at 2-3. Alcoa notes that "during clarification sessions, BPA staff said that this change [in the definition of augmentation] is not intended to prevent FBS replacement purchases to serve the DSIs, including up to the level of the Federal Base System... ." *Id.* at 3.

BPA Staff's Position

TRM section 3.2.1.3, Power Purchases for Service to DSIs and Other Loads, states: "If BPA decides to sell power to the DSIs or to other loads not served at the Tier 1 or Tier 2 Rates, power purchased for such purposes will not be included in the Tier 1 System Capability. The costs of power purchases for such service may be included in the Composite Cost Pool." TRM-12-E-BPA-20 at 24.

Not including the purchases for DSI load in the Tier 1 System Capability means that Slice customers will not receive a share of the output of those resources. Including the costs in the Composite Cost Pool means that all PF customers share in the costs. Staff used the term "may be" rather than "will" because BPA is not deciding those issues in this TRM, but in future 7(i) Processes.

Although the TRM precludes power purchased for DSI service from being included in Tier 1 System Capability, it does not preclude inclusion of such power in the FBS. Tier 1 System Capability is separate and distinct from the FBS. Staff believes the TRM is sufficiently clear that it does not prevent FBS replacement purchases to serve the DSIs, including up to the level of the Federal Base System.

Evaluation of Positions

There is confusion in the Alcoa Brief that arose from the early TRM draft. It is Alcoa's shorthand phrase "augment the FBS," that leads to the confusion. The actual term is to "replace" the FBS. 16 U.S.C. § 839a(10)(C). It is better to use the generic term "augment" to refer to adding resources to the Federal system, whether it is FBS or new resource.

Thus, Staff edited the TRM to remove the reference to "augmenting" for DSI loads. This removal allows purchases for DSIs *and* for other non-CHWM customers that do not have to be shared with Slice customers. Otherwise, BPA would have to purchase about one-third more power than needed to serve DSI load.

The reference to augmenting the FBS was also removed for other reasons. First, whether resource additions are FBS replacements or new resources is not something BPA should determine in the TRM, because the ability to replace the FBS is limited. Using this limited ability for the DSIs may result in a situation when BPA could not replace the FBS with resources for service to Above-RHWM Load. This may compromise the ability to tier the PF rate.

Second, in order to be able to serve the DSIs it is not necessary to put power purchased for such service into the FBS. Given current circumstances in BPA ratemaking methodologies, any DSI load would not be allocated any FBS costs, and whether the purchased resource is put in the FBS or new resources would not much affect the cost allocations. The DSIs are allocated a mix of exchange and new resources. The placement of the DSI resource would change the mix of exchange and new resources, but would in no event result in FBS resources being allocated to the DSIs.

Third, in any event, the mix of resources allocated to DSI service does not affect the rate the DSIs pay. That rate is determined pursuant to section 7(c). The determination of the resources in the FBS and new resource pools is a separate decision that BPA will make at the appropriate time, a decision that should not be pre-decided in the TRM.

Decision

The TRM is sufficiently clear that it cannot be interpreted to prevent FBS replacement purchases to serve the DSIs, including up to the level of the Federal Base System.

Issue 5

Whether BPA should explicitly include a reference in the TRM that BPA makes an Industrial Firm Power (IP) sale to the DSIs and if BPA purchases FBS replacement power to serve that load under the IP rate, then BPA will spread those costs across all customers.

Parties' Positions

Alcoa states its concern that unless BPA clarifies that costs of augmenting the FBS for purposes of serving the DSIs are spread over all sales, preference customers can (and likely will) argue at a later time that no FBS power is available for the DSIs and that DSI loads must be served at the price of new resources, purchased at the full incremental cost, which has the same effect as throwing the DSIs on the market. Alcoa Brief, TRM-12-B-AL-01, at 29-30.

BPA Staff's Position

In supplemental testimony and its Motion to Supplement the Record and Allow for Comment, BPA Staff proposed “to clarify that if BPA decides to make a power sale to DSIs under the IP rate that (1) the rate would be set consistent with section 7(c) of the Northwest Power Act based on the costs that will be allocated in the 7(i) Process and (2) nothing in the TRM would prohibit the allocation of any costs of such service to the Composite Cost Pool.” Cherry, *et al.*, TRM-12-E-BPA-10, at 9; *see also* TRM-12-E-BPA-20 at 24 (section 3.2.1.3); *and* BPA’s Motion to Supplement Record, TRM-12-M-BPA-11, Attachment A.

Evaluation of Positions

Staff proposed the changes from the initial to the supplemental TRM because the “Initial Proposal contained language that was more specific than needed, potentially deciding issues that were intended to be reserved for later 7(i) Processes.” Cherry, *et al.*, TRM-12-E-BPA-10, at 9. After releasing the TRM with its rebuttal testimony, Staff worked with Alcoa and other parties in settlement discussions to craft the language submitted in BPA’s Motion to Supplement Record, TRM-12-M-BPA-11, Attachment A. Coupled with TRM section 3.2.1.3, this language addresses Alcoa’s concern by clarifying that rates set to recover the costs allocated to the Composite Cost Pool are paid by all PF customers.

Decision

The TRM is sufficiently clear that if BPA makes an IP power sale to the DSIs and if BPA purchases FBS replacement power to serve that load under the IP rate, then the allocation of such costs will be done in accordance with the rate directives in section 7 of the Northwest Power Act.

Issue 6

Whether the TRM preserves the proper construction of the IP rate such that it is “equitable” and similarly close to the PF rate and such that it will reflect a revenue credit for secondary energy sales.

Parties’ Positions

Alcoa argues that section 7(c) of the Northwest Power Act must govern the rate for power service to the DSIs such that the IP rate is “equitable” in relation to the rates that preference customers charge to the industrial customers they serve. Alcoa Brief, TRM-12-B-AL-01, at 21-30. Alcoa states that the Northwest Power Act compels that the IP rate be similarly close to the PF rate. *Id.* at 23.

Alcoa states that it wants to preserve the “properly constructed” IP rate by ensuring that the PF rate (on which the industrial margin is based) includes a revenue credit for secondary energy sales. Alcoa Brief, TRM-12-B-AL-01, at 27-29. Alcoa suggests that BPA should clarify that the ‘base’ PF rate to which a typical margin will be added in calculating the DSI rate is the same as the PF rate that is accorded a surplus revenue credit. Alcoa Brief, TRM-12-BPA-AL-01, at 28.

BPA Staff’s Position

In rebuttal testimony, BPA Staff stated that “[b]ecause section 7(c) requires that the IP rate be set using the applicable PF Preference rate as a starting point, the IP rate will receive the benefit of the secondary energy revenue credit to the same extent that such credit is included in the applicable wholesale rate, which has been BPA’s historical practice.” Cherry, *et al.*, TRM-12-E-BPA-15, at 15. However, specific decisions regarding the IP rate will be made in an applicable section 7(i) proceeding, consistent with the requirements of section 7(c) of the Northwest Power Act. *Id.* The TRM is not the proper place for such decisions.

Evaluation of Positions

Alcoa misstates the BPA calculation of the DSI rate pursuant to section 7(c). The calculation does not begin with the “PF rate.” Rather, it begins with the “applicable wholesale rate.” The “applicable wholesale rate” is the weighted average of service to preference customer requirements loads at the PF Preference and the NR rates. *See* 1985 Administrator’s Final Record of Decision, WP-85-A-02, at 244. Should a preference customer request service to an

NLSL at the NR rate, that load and rate will be included in the calculation of the “applicable wholesale rate.”

There are many aspects of cost and revenue credit allocations that are not addressed in the TRM, because the TRM deals with tiering the PF Preference rate, not how cost and revenue allocations will be performed. Such cost and revenue allocations are governed by section 7 of the Northwest Power Act. The TRM does not upset those instructions. *See* ROD section 3.1. All rates will continue to be set according to section 7 of the Northwest Power Act; tiering is simply a rate design added to the PF Preference rate. This raises no cause for concern that other rates will be deprived of their share of the secondary revenue credit.

Once again, Alcoa is confusing the FBS with the Tier 1 System. The two are not identical. The question posed by Alcoa seems to imply that *all* of BPA’s customers will have a portion of their loads met with FBS resources. Such is not the case. Section 7(b)(1) clearly states how the FBS is to be used: first to the general requirements of the publics and the participants in the REP. When the FBS is exhausted, remaining load of these customers is served with exchange resources. If these two sources are not sufficient, and in the WP-07 rate proceeding they were not, these customers are then served with new resources. Therefore, should BPA sell power to the DSIs, they generally would be served with a mix of exchange and new resources, not FBS resources. Under BPA’s ratemaking, the DSI load pool would be credited with a proportionate share of secondary revenues based on the amount of FBS and new resources serving the DSI loads. In the WP-07 rates, the DSIs would not be served with any FBS. Therefore, the DSIs would receive a secondary revenue credit based on the amount of new resources allocated to the DSI load pool.

In any case, Alcoa misses the point. The DSI rate is set based on section 7(c) of the Northwest Power Act. As such, whether the DSI load pool is allocated any secondary revenue credit does not affect the DSI rate level. To the extent the PF Preference rate receives a secondary revenue credit, such credit will be reflected in the IP rate. Thus, BPA does not need to clarify this treatment of the DSI rate in the TRM. The TRM does not govern the DSI rate; section 7(c) of the Northwest Power Act does. Language stating such is not necessary in a document governing the rate design for the PF Preference rate.

Decision

The TRM does not govern the design of the DSI rate; section 7(c) of the Northwest Power Act does. Accordingly, BPA does not need to clarify the treatment of the DSI rate in the TRM.

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6.0 Issues Outside the Scope of the TRM

6.1 Flexibility for the Addition of Non-Federal Resources

Issue 1

Whether BPA has provided sufficient flexibility for the addition of Non-Federal Resources.

Parties' Positions

NRU and WPAG, joined by Clatskanie PUD, McMinnville, EWEB, Central Lincoln PUD, Tillamook PUD, and Canby Utility Board, assert that BPA did not provide sufficient flexibility in the contract templates regarding how resources could be added and applied. NRU Brief, TRM-12-B-NR-01, at 2-3; WPAG Brief, TRM-12-B-WA-01, at 17-19; Clatskanie Joinder, TRM-12-M-CK-02; McMinnville Joinder, TRM-12-MW-01; EWEB Joinder, TRM-12-M-EW-01; Central Lincoln Joinder, TRM-12-M-CL-01; Tillamook Joinder, TRM-12-M-TI-01; Canby Joinder, TRM-12-M-CA-01. NRU takes issue with some of the contractual requirements BPA included for the provision of Resource Support Services (RSS). NRU Brief, TRM-12-B-NR-01, at 3. WPAG takes issue with BPA's proposal in the TRM to apply shaping charges to resource shapes that are not in a flat annual block. WPAG Brief, TRM-12-B-WA-01, at 18. Both parties argue that, when taken together, the requirements under the TRM and CHWM Contracts would stifle Non-Federal Resource development. NRU Brief, TRM-12-B-NR-01, at 3; WPAG Brief, TRM-12-B-WA-01, at 17.

BPA Staff's Position

These issues raised by parties are outside of the scope of this proceeding.

Evaluation of Positions

The issue raised by NRU and WPAG pertains to the design and scope of power products and terms and conditions of the Regional Dialogue contracts, which are addressed in the Regional Dialogue Contract Policy Record of Decision (CP ROD), at 19-21. The application of shaping charges to resource shapes that are not in a flat annual block is how BPA staff proposed to carry out the decision in the CP ROD to have a flat annual block shape as the benchmark shape. In accordance with the Federal Register Notice, power product and contract issues such as these are outside of the scope of this proceeding. *2012 Tiered Rate Methodology Proceeding; Public Hearings and Opportunities for Public Review and Comment*, 73 Fed. Reg. 24961 (2008), at 24,962.

Decision

The issue of whether BPA has provided sufficient flexibility for the addition of Non-Federal Resources is outside the scope of this proceeding.

Issue 2

Whether transfer customers are disadvantaged by BPA's current RSS baseline approach, which requires customers to wheel their Non-Federal Resources to the BPA Balancing Authority Area to obtain RSS from BPA.

Parties' Positions

NRU supports comments provided by WMG&T in testimony. NRU Brief, TRM-12-B-NR-01, at 3. NRU argues that BPA's RSS requirement that Non-Federal Resources be wheeled to the BPA Balancing Authority Area unfairly disadvantages customers served by transfer. *Id.*

BPA Staff's Position

These issues raised by parties are outside of the scope of this proceeding.

Evaluation of Positions

Transfer customers are BPA customers whose load is partially or completely served by delivery over another entity's transmission system. BPA contracts with another transmission provider to transfer Federal power across its transmission system for delivery to BPA's customer.

The issue raised by NRU pertains to the design and scope of power products and terms and conditions of the Regional Dialogue contracts. This issue is addressed in the CP ROD, at 43-45. In accordance with the Federal Register Notice, issues such as these pertaining to power products and contracts are outside of the scope of this proceeding. *2012 Tiered Rate Methodology Proceeding; Public Hearings and Opportunities for Public Review and Comment*, 73 Fed. Reg. 24961 (2008), at 24962.

Decision

The issue regarding whether transfer customers are disadvantaged by BPA's current RSS baseline approach, which requires customers to wheel their Non-Federal Resources to the BPA Balancing Authority Area to obtain RSS from BPA, is outside the scope of this proceeding.

Issue 3

Whether BPA arbitrarily and unreasonably restricts the full use of a customer's Non-Federal Resource by requiring customers to take Transmission Scheduling Service (TSS), while not allowing customers to schedule their resources not going to load on Point-to-Point (PTP) transmission.

Parties' Positions

McMinnville argues that the TRM and CHWM Contract combine to arbitrarily and unreasonably restrict the full use of a customer's Non-Federal Resources. McMinnville Brief, TRM-12-B-MW-01, at 6. McMinnville points out that BPA requires in the Load Following contract that a customer take BPA TSS if the customer also purchases Diurnal Flattening Service. *Id.* at 3. McMinnville states that it is opposed to this requirement because Transmission Services does not allow Network Transmission (NT) contract holders to have multiple parties scheduling their service even if the second party is scheduling its resources on PTP for marketing purposes. *Id.* Additionally, because neither the TRM nor the CHWM Contract provides BPA with authority to remarket that portion of a customer's resource that may exceed the customer's Above-RHWM Load (except if the customer has taken DFS for that resource), McMinnville states that BPA has created a situation where customers will not be able to take full advantage of their new Non-Federal Resources. *Id.* at 5.

BPA Staff's Position

These issues raised by McMinnville are outside the scope of this proceeding. Furthermore, McMinnville offered no testimony or other evidence regarding its contention during the evidentiary phase and raised it for the first time in its brief.

Evaluation of Positions

The issues raised by McMinnville pertain to the design and scope of power products and terms and conditions of the Regional Dialogue contracts. In accordance with the Federal Register Notice, these issues are outside of the scope of this proceeding. *2012 Tiered Rate Methodology Proceeding; Public Hearings and Opportunities for Public Review and Comment*, 73 Fed. Reg. 24961 (2008), at 24962. Moreover, they also pertain to a Transmission Services Business Practice, which is also outside the scope of this proceeding because Power Services does not have authority to adopt a new Transmission Business Practice on behalf of Transmission Services. Transmission Services has been made aware of this issue and intends to propose a change to its Business Practice through the appropriate channels.

Decision

The issues of whether BPA arbitrarily and unreasonably restricts the full use of a customer's Non-Federal Resource by requiring customers to take TSS, while not allowing customers to schedule their resources not going to load on PTP transmission, are outside the scope of this proceeding.

6.2 Expiration of New Federal Resources Added to Serve Loads During the CHWM Contract Term

Issue 1

Whether BPA has created sufficient certainty regarding the treatment of Federal resource acquisitions whose costs are allocated to Tier 2 Rates when the term of the Regional Dialogue contracts concludes.

Parties' Positions

NRU raises concerns about what happens to resources BPA acquires to serve loads at Tier 2 Rates when the CHWM Contracts expire and requests that BPA commit to working with customers to deal with this well before the end of FY 2028. NRU Brief, TRM-12-B-NR-01, at 4.

BPA Staff's Position

The TRM is not the appropriate place to address this issue. BPA Staff concluded in its rebuttal testimony that “[g]iven the number of unknowns and the fact that this issue addresses matters outside the scope of the TRM, we do not believe it is proper to address this issue at this time in the TRM.” Cherry, *et al.*, TRM-12-E-BPA-15, at 29. The concern raised by NRU is one that can be addressed in future discussions with customers about the follow-on contracts to the Regional Dialogue contract. *Id.* at 28.

Evaluation of Positions

NRU expresses concern over a potential “resource cliff” that could occur at the end of the Regional Dialogue contracts. NRU Brief, TRM-12-B-NR-01, at 8. NRU queries, if BPA acquires significant amounts of resources to serve load at Tier 2 Rates, what would happen regarding those resources, including how the cost of the resources will be reflected in the rates, when the contracts end. *Id.* In testimony, NRU explains that because NRU is concerned over higher prices in the future, NRU suggests that BPA should agree to work with customers to develop a strategy to deal with any potential resource cliff. *Id.* at 9.

BPA acknowledges NRU’s concern, and recognizes there could be rate impacts in the future caused by the cost of resources BPA acquires to supply customers’ Above-RHWM Loads during the term of the Regional Dialogue contracts. Length of resource acquisition will be the subject of future Resource Program and Tier 2 Rate Alternative discussions. How to allocate the costs of such resources whose contracts extend beyond the life of the CHWM Contracts will be at issue in future 7(i) Processes as well as discussions regarding the post-CHWM Contracts. How BPA will serve Public customer loads after the CHWM Contracts expire will likely be the subject of future policy, contract, and rate design discussions. The CP ROD at 22-23 contains further explanation of why such issues are not appropriate for consideration at this time.

Decision

The question of whether BPA has created sufficient certainty regarding the treatment of Federal resource acquisitions whose costs are allocated to Tier 2 Rates when the term of the Regional Dialogue contracts concludes is outside the scope of this proceeding.

6.3 Definition of Total Retail Load

Issue

Whether the TRM definition of Total Retail Load (TRL) excludes load that BPA is obligated to serve under the Northwest Power Act.

Parties' Positions

Clatskanie argues that the term “Total Retail Load” or “TRL” would exclude portions of its existing retail loads served by the utility and that such loads qualify as load that BPA must serve under section 5(b)(1) and at Tier 1 Rates. Clatskanie Brief, TRM-12-B-CK-01, at 11

BPA Staff's Position

This issue is outside the scope of the TRM.

Evaluation of Positions

Because this issue is focused on the definition of TRL as it is included in BPA's Regional Dialogue power sales contract, and because it affects BPA net requirements load determinations that define BPA's load service obligations under the contract, BPA addresses the issue in its Regional Dialogue Contract Policy Record of Decision.

Decision

This issue is outside the scope of the TRM and instead is addressed in BPA's Regional Dialogue Contract Policy Record of Decision at 92-94.

6.4 Transmission to Enable Non-Federal Resource Development

Issue

Whether BPA has created sufficient certainty regarding availability of transmission to take Non-Federal Resources to load during the term of Regional Dialogue contracts for customers served by transfer and by the South Idaho Exchange.

Parties' Positions

NRU expresses concern about the availability of transmission to enable Non-Federal Resource development. NRU Brief, TRM-12-B-NR-01, at 2. In particular, NRU states concern about the availability of transmission for non-Federal deliveries to customers served by transfer and by the South Idaho Exchange. *Id.*

BPA Staff's Position

This issue is outside of the scope of this proceeding because it is addressed in other Records of Decision.

Evaluation of Positions

The South Idaho Exchange is an agreement between BPA and PacifiCorp whereby PacifiCorp delivers an amount of power to BPA customers on PacifiCorp's South Idaho transmission system and BPA delivers a like amount of power to PacifiCorp loads on BPA's transmission system in Southwest Oregon. This agreement saves significant transmission charges and losses for both BPA and PacifiCorp.

The issues raised by NRU regarding transmission for Non-Federal Resources are outside of the scope of this proceeding. The issue of Non-Federal Resource deliveries to customers served by the South Idaho Exchange is addressed in the CP ROD, at 77. The issue of Non-Federal Resource deliveries to customers served by transfer was addressed in the 2007 Long-Term Regional Dialogue Record of Decision, at 236-237.

Decision

The issue regarding whether BPA has created sufficient certainty regarding availability of transmission to take Non-Federal Resources to load during the term of Regional Dialogue contracts for customers served by Transfer and by the South Idaho Exchange is outside the scope of this proceeding.

7.0 Participant Comments

7.1 Introduction

This section summarizes and evaluates the comments of participants in BPA's TRM rate proceeding. Participants are persons and organizations who comment on BPA's rate proposal but do not take part in the formal section 7(i) proceedings. Comments of participants are part of the official record of the section 7(i) proceeding and are considered when the Administrator makes his decisions as set forth in this ROD.

The TRM-12 participant comment period commenced after publication of the Federal Register Notice on May 6, 2008 (73 Fed. Reg. 24961 (2008)). The Federal Register Notice can be viewed at the BPA website:

http://www.bpa.gov/corporate/ratecase/2008/2008_TRM/Docs/FRN_TRM_published_second.pdf

The participant comment period ended August 13, 2008. BPA received nine written comments in the TRM case, most from BPA public utility customers. Comments can be viewed at the BPA website:

<http://www.bpa.gov/applications/publiccomments/CommentList.aspx?ID=33>

BPA reviewed the participants' portion of the record and identified those concerns expressed by the participants to be addressed in this section of the ROD. A summary of the letters BPA received during the participant comment period, along with discussions of those concerns, is provided below.

7.2 Evaluation of Participant Comments

7.2.1 Process Scheduling

Benton Rural Electric Association (Benton REA) comments that BPA's accelerated schedule for addressing multiple issues, including development of the TRM, has made it impossible for the staff of preference utility customers to meaningfully participate in these processes and does not satisfy BPA's obligation to provide public involvement. TRM0003 at 1-2. Benton REA asks BPA to reconsider its schedules for these processes.

BPA notes that Benton REA is a party to this proceeding and is therefore ineligible to avail itself of the participant comment provisions of BPA's *Procedures*. Benton REA is a member of both NRU and WPAG, both of which intervened individually and on behalf of their individual members, including organizations. Nevertheless, BPA will respond to Benton REA's concerns. BPA is aware that conducting multiple processes simultaneously and on tight schedules can be a hardship for any party that wishes to be involved. BPA would note however, that Benton REA was very ably represented during these proceedings by both NRU and WPAG. NRU and WPAG representatives and counsel actively participated in this proceeding and were present at virtually all of the formal and informal aspects of this proceeding. NRU and WPAG both filed testimony and briefs in this proceeding on behalf of members including Benton REA. BPA also is aware that the stakes are high, and not to accomplish the region's goals related to the Regional Dialogue would come at great cost. Completing Regional Dialogue requires the completion of

policy, contracts, and a rate methodology that must all work together. Each of these requires a separate public process. In order to make sure the contracts and TRM will work together meant they needed to be done concurrently. While these last aspects of these processes appear to be on an accelerated schedule, the process has been underway since 2002. The 2007 Long-Term Regional Dialogue Policy (RD Policy) and Record of Decision (RD Policy ROD) resulted from a five-year-long discussion that began when the Joint Customers submitted a power allocation proposal to BPA in April 2002. The RD Policy and RD Policy ROD defined BPA's long-term power supply role for the region in a way that keeps the economic benefit of the Federal Columbia River Power System in the Northwest. The RD Policy was designed to provide the region's utilities with the clarity and certainty they need to make their power acquisition decisions for the long term. The RD Policy clarified that the goal was for public customers to sign new BPA 20-year wholesale power contracts in 2008 in time for regional utilities to arrange how they will receive power beyond what they have requested BPA to supply. Utilities need certainty of power supply, and BPA needs certainty of commitment levels to allow it to acquire any needed power it is asked to provide by the time it is needed.

The other part of the Regional Dialogue equation is tiered rates. Having a tiered Priority Firm Power rate will allow the region to keep sight of the real value of the low-cost, clean Federal power system. That value was obscured in the past when costs of the Federal system were melded in rates with the costs of additional resources acquired to server load. BPA's objective has been to provide customers with certainty about cost allocation and rate design by having the TRM in place before preference customers sign CHWM Contracts in December 2008. BPA's original schedule would have resulted in an earlier ROD; however, the ROD was delayed until now in large part to accommodate many days of negotiations between BPA and the rate case parties, which eliminated a large number of the contested issues that this ROD would have otherwise had to address. However, even with the delay, this ROD has been completed before customers must sign their CHWM Contracts. The Contract Policy ROD was recently completed. Although actual rate levels will be set in subsequent rate cases, the TRM describes the design of rates and billing determinants for the products BPA is offering in the CHWM Contracts.

Besides Regional Dialogue, the other major reason for conducting so many processes this year is a series of rulings by the U.S. Court of Appeals for the Ninth Circuit. Following final approval of BPA's WP-02 rates by the Federal Energy Regulatory Commission, a number of parties challenged the WP-02 power rates in the Ninth Circuit. In *Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037 (9th Cir. 2007) (*Golden NW*), the Court held that BPA had improperly allocated Residential Exchange Program (REP) Settlement Agreement costs to BPA's rate for preference customers. During the litigation of *Golden NW*, but prior to the Court's decision, BPA conducted the WP-07 rate case to establish power rates for FY 2007-2009. In establishing these rates, BPA allocated REP settlement costs in the same manner as in BPA's WP-02 rates. Because the Court held in *Golden NW* that BPA's allocation of REP settlement costs in its WP-02 rates was improper, BPA's allocation of such costs in the WP-07 rates was similarly flawed.

The Court also held that BPA's WP-02 fish and wildlife cost estimates, and by extension the rates set pursuant to those estimates, were not supported by substantial evidence. BPA needed to take steps to ensure that its final WP-07 Supplemental rates for FY 2009 would be based on the

most recent projections of fish and wildlife costs available at the time of rate development. As BPA is required to do, BPA provided opportunities for fish and wildlife managers and others to provide input to BPA regarding fish and wildlife program costs for FY 2009 to be used in the development of BPA's final WP-07 Supplemental rates.

In a companion case to *Golden NW*, the Court held that BPA's REP Settlement Agreements with the IOUs were contrary to the Northwest Power Act. *Portland General Elec. Co. v. Bonneville Power Admin.*, 501 F.3d 1009 (9th Cir. 2007) (*PGE*). Subsequently, the Court also reviewed three petitions for review challenging Load Reduction Agreements (LRAs) BPA executed with two IOUs during the energy crisis of 2000-2001. The Court dismissed two of the petitions for lack of jurisdiction and one petition as moot. The Court also reviewed challenges to amendments to the REP Settlement Agreements signed in 2004. In *Public Utility Dist. No. 1 of Snohomish County, Wash. v. Bonneville Power Admin.*, 506 F.3d 1145 (9th Cir. 2007) (*Snohomish*), the Court remanded to BPA the amendments and a contract provision establishing a Reduction of Risk Discount.

BPA had to respond to these decisions of the Court. Because the ratemaking and REP issues are interrelated, BPA decided to respond to the Court's decisions in the WP-07 Supplemental Proceeding. That effort concluded in September 2008. As a result of the Court's decision, BPA needed to reinstate the REP by negotiating new Residential Purchase and Sale Agreements (RPSAs) with its utility customers. In the wake of the Court's decisions in *PGE* and *Golden NW* and based in part on comments received, BPA began an expedited process, beginning with a series of public workshops, to revise the Average System Cost (ASC) methodology. The expedited process was created to enable BPA to develop preliminary ASCs under the proposed ASC methodology for purposes of the needed REP cost assumptions in BPA's WP-07 Supplemental rate proceeding. The expedited process was a valuable tool to develop and test, in concert with the region, an ASC Methodology that would be legally sustainable, efficient, and durable over time.

BPA has made efforts to reduce the number of processes occurring simultaneously. For example, BPA deferred the Resource Program. Under the original schedule, BPA would have issued a draft Resource Program in December 2008 and the final in early 2009. The original schedule was designed to make the draft Resource Program analysis available to customers before they signed Regional Dialogue contracts. Under the new schedule, the draft Resource Program will be issued for public review in July 2009 and the final in October 2009. Delaying the schedule still will give customers information on resource acquisition types and amounts before they must make their Tier 2 power purchase decision for 2012-2014.

In sum, BPA is acutely aware of the difficulty in participating in multiple processes simultaneously and on tight schedules. Yet, BPA believes the results of completing the current processes in 2008 will prove to be the best for the region. Besides the reasons articulated above, having to bring a new Federal administration up to speed on the region's issues could cost precious time and deprive parties the certainty they need now to plan for the future. BPA appreciates its customers' and other parties' participation and thoughtful attention to the issues.

Charles Pace states that if implemented on the schedule/timeline proposed, the TRM will require that utilities make decisions as early as December 2008 that will affect their ability to provide service from FY 2012 through FY 2014 and over the remainder of the 20-year term of the regional dialogue contract without a reasonable basis for determining what amount of power, and which products/services, BPA may actually be able to deliver and at what cost. TRM0009 at 3-4.

BPA notes that the issues raised by Mr. Pace deal with contract issues and are not within the scope of this proceeding. The TRM contains no deadlines for decisions by December 2008 for either the FY 2012-2014 period or for the term of the Regional Dialogue contracts. Further, BPA notes that actual rates are not being established at this time. Therefore, it is not possible at this time to determine the either the amounts of power BPA will be delivering or the costs that BPA will incur to deliver the power.

7.2.2 New Publics

Public Utility District No. 1 of Skagit County (Skagit PUD) and Public Utility District No. 1 of Jefferson County (Jefferson PUD) comment both individually and through DHittle & Associates, Inc. The individual utilities are all parties of right and therefore ineligible to avail themselves of the participant comment provisions of BPA's *Procedures*. However, BPA will respond to the concerns. Skagit PUD and Jefferson PUD stated that they believe that the greatest public good would occur if BPA coordinates with potential new preference customers on a case-by-case basis regarding the timing of when a determination is made that the new utility has met BPA's standards of service and when and for how long the binding request for service can be made. TRM0010 at 1; TRM0007 at 1; *see also* TRM0002 at 2. They add that the TRM should not force a new preference electric utility to operate for a full three years using only owned generation, non-Federal power, and/or a Tier 2 or TAC [priced] power product. This would be a significant financial disincentive to forming a new preference utility and will likely result in attempts by some to 'game the system' in a way that could harm regional planning. TRM0002, at 2. A similar issue is also raised by ATNI testimony, which expresses the same concern that the three-year binding notice requirement for service to a New Public under tiered rates is a disincentive to the formation of New Publics. *See* ATNI testimony, TRM-12-E-AT-01, at 9, and ATNI Brief, TRM-12-B-AT-01. Springfield Utility Board (SUB) states support for the TRM's description of service requirements for new public utilities. TRM0008 at 4.

In response to these concerns, BPA has shortened the notice period needed for small new public utilities to begin purchasing at Tier 1 rates. Cherry, *et al.*, TRM-12-E-BPA-10, at 5-6; ROD section 3.3.4. As noted by parties to this proceeding, BPA needs less time to acquire the needed capability to meet a relatively small new load obligation. *Id.* at 5. Thus, new public utilities smaller than 10 aMW must provide binding notice to BPA by July 1 of the forecast year (the fiscal year ending one full year before a rate period starts) prior to the rate period during which it will begin purchasing from BPA at Tier 1 rates. *Id.* However, the forming utility must still meet BPA's Standards for Service before providing the required notice. TRM-12-E-BPA-20 at 39-40.

The argument that a three-year binding notice requirement after meeting BPA's Standards for Service results in a forming utility being faced with three years of service at Tier 2 or TAC rates

while servicing infrastructure-related debt is not necessarily true. The Standards for Service currently in effect do not require that a forming utility have a “turn-key” ability to serve customers or a fully completed infrastructure. Bonneville Power Administration’s Standards for Service, BPA (January 2000). As a result, the amount of time between when a forming utility begins serving its customers (and debt) and when it will be eligible to receive service from BPA under tiered rates may be substantially less than the full required notice period.

BPA has a valid need to be able to plan for substantial new loads and to determine the cost of serving that load in time for the rate case that must address those costs. Accordingly, New Publics of 10 aMW or greater still must provide binding notice to BPA by the earlier of 1) three years prior to the date the new utility would begin purchasing at Tier 1 rates, or 2) July 1 of the forecast year prior to the rate period in which the new utility would begin purchasing at Tier 1 rates. TRM-12-E-BPA-20 at 39-40.

It should be noted that the TRM does not address the requirements or process for a new utility to qualify under BPA’s Standards for Service. Cherry, *et al.*, TRM-12-E-BPA-15, at 20. BPA does not intend that the TRM will change BPA’s current practice of coordinating with new utilities on a case-by-case basis, as Skagit PUD and Jefferson PUD request, regarding qualifying and contracting for power deliveries from BPA. However, such coordination will not modify the binding notice requirements established in the TRM.

The change that BPA has made in the notice requirement for small New Publics should reduce the barriers Skagit and Jefferson PUDs perceived for new public utilities forming. At the same time, BPA will retain the ability to forecast revenue requirements for the additional load in the applicable rate case and to include the new loads and related costs in the rates for the applicable rate period.

7.2.3 TRM Overview

Benton REA comments that it is not in the best interests of BPA, public power, or Benton REA to implement the TRM. TRM0004 at 4; TRM0011 at 3. Benton REA states several concerns. First, Benton REA states that because the TRM is a rate construct memorialized in a policy, not a contract, it does not secure the preference customers’ claim to the output of the FBS any more than is currently the case. TRM0004 at 2. Second, Benton REA states that the TRM, although it memorializes a rate design for the term of the contract, does not provide service to preference customers at the lowest possible cost-based rate—the load shaping charge is based on market, not cost, and the demand charge also is not cost-based. *Id.* Third, Benton REA states that the TRM highlights two facts that may not be in the region’s best interests—that Tier 1 rates will be very inexpensive and well below regional and national market rates, and that regional preference utilities are willing to pay BPA market prices for power at the margin. Benton claims that these two facts may increase the region’s political exposure. *Id.* Fourth, Benton REA states that the value of the FBS likely will diminish over time; thus, the TRM does not protect preference and could actually lead to its demise. *Id.* at 3. Benton REA also states that preference customers sought protection in the TRM for load following customers from the value of secondary energy sales being used for purposes other than reducing the cost of power sold at Tier 1 rates. TRM0011 at 2.

As noted above, Benton REA is a party to this proceeding and is therefore ineligible to avail itself of the participant comment provisions of BPA's *Procedures*. Because Benton REA's concerns were raised in the brief filed by WPAG and addressed elsewhere in this ROD, BPA will not respond to these issues again. *See* ROD section 2.0.

7.2.4 Cost Allocation

Charles Pace states that the cost-allocation strategy and approach in the TRM will apparently incorporate within the Composite Cost Pool for Tier 1 the funding commitments that BPA agreed to in the Columbia Basin Fish Accords. Mr. Pace states that this allocation would seem to defeat a primary objective of the TRM, i.e., to ensure that preference customers purchasing power at Tier 1 rates do not pay the costs of providing service at Tier 2 rates for public preference customers with above-RHWM load or the incremental costs of providing power for non-preference customers. TRM0009 at 3.

First and foremost, the merits and cost levels of the Columbia Basin Fish Accords are outside the scope of this proceeding (and outside the scope of any section 7(i) proceeding). BPA's section 7(i) proceedings do not include evaluation of program costs, but only how those costs are allocated and recovered in rates. The costs BPA includes in its rates for fish and wildlife mitigation are part of Federal base system costs for ratemaking purposes. In the process of setting a tiered Priority Firm rate in future rate cases, BPA will perform its entire ratesetting process, including adjustments, until it has determined the costs allocated to the PF Preference rate. Only then will PF Preference costs be allocated to the Composite, Slice, and Non-Slice cost pools as shown in the Allocated Tiered Cost Table. BPA will use the TRM cost allocation principles as the guideline for allocating costs. TRM-12-E-BPA-20 at 3-4. TRM section 2.6 describes the actions BPA will take if, for purposes of cost recovery, BPA determines that it must reallocate to a Tier 1 cost pool costs that the TRM indicates otherwise would be allocated to a Tier 2 cost pool. *Id.* at 3-4. These actions are designed to protect BPA's customers but will not be allowed to override or frustrate the Administrator's responsibility to recover costs and timely repay the U.S. Treasury. *Id.* at 4.

7.2.5 CHWM Calculation

Emerald People's Utility District (EPUD) and Power Resources Cooperative (PRC) state that renewable resources that provide direct benefits (by reducing the release of greenhouse gases) should be excluded from the CHWM calculation. TRM0006 at 2. Specifically, EPUD and PRC describe two existing landfill gas plants that should be included as part of the existing renewable resource exception in the CHWM calculation, regardless of the year they first operated, because of their unique benefits as renewable resources. *Id.* EPUD and PRC state that having to purchase power at Tier 2 rates to replace the output from the landfill gas plants will penalize two customers \$1.9 million annually. *Id.* at 3.

EPUD is a party of right and therefore ineligible to avail itself of the participant comment provisions of BPA's *Procedures*. PRC is a companion business of PNGC, which intervened individually and on behalf of its members. However, BPA will respond to the concerns. The

TRM states that the output of renewable resources added during the term of the Subscription contracts will be excluded from the calculation of CHWMs so as not to discourage the development of renewable resources. TRM-12-E-BPA-20 at xii. The decision to exclude such resources was made in the RD Policy ROD (July 2007); *see* RD Policy ROD at 76-77. On June 6, 2008, BPA issued for review and comment its “Clarification on the Use of Customer Resource Amounts for High Water Mark Calculations.” In the cover letter BPA stated that it was not revisiting the July 2007 Policy decisions on the use of FY 2010 resources for the CHWM calculation but proposed to correct the identified inaccuracies in the Exhibit C FY 2010 resource numbers. BPA received participant comment TRM0006 in response to that letter and attachment. BPA has discussed this issue further and has decided that it will not deviate from the RD Policy. BPA wishes to stay with its stated basis for calculating CHWMs, which was based on Regional Dialogue discussions, and will not create a CHWM exception for renewable resources that come online after FY 2010. Changing the decision in the Policy would result in reduced certainty for all utilities and increases to the CHWMs of utilities with this one type of resource, potentially to the detriment of other utilities, whose CHWMs would decrease.

SUB requests that BPA clarify the treatment of conservation achieved in FY 2010 regarding calculation of CHWMs. TRM0008 at 2. SUB states that customers are required to report every six months on conservation achieved. SUB is unclear how conservation achieved in the second half of FY 2010 would be treated in the CHWM Conservation Adjustment. TRM0008 at 3.

TRM section 4.1.4 describes the Conservation Adjustment to Scaled Eligible Load, and TRM Attachment D provides an example of the calculation of the Conservation Adjustment. TRM-12-E-BPA-20 at 37, and Attachment D. To provide as equitable a process as possible, BPA will review individual conservation measures that are 0.5 aMW or larger and custom projects that are 0.5 aMW or larger implemented during FY 2010 and prorate the savings by month. Projects implemented on or before the 15th of the month will be given full credit for the prorated savings achieved in that month; those implemented on the 16th of the month or later will receive no credit for the month. For example, a 1.0 aMW project that is implemented on March 17, 2010, would receive 0.50 aMW credit toward the conservation adjustment, as it will have been in place for 6 months during FY 2010. Prorating will be reviewed from the date (month) measures and custom projects are implemented and start reducing energy usage, not when monitoring and verification are completed. Measures and custom projects that are 0.5 aMW and larger and implemented by September 30, 2009, will not be prorated, because they would be in place for all of FY 2010.

For measures and projects smaller than 0.5 aMW, before a final determination is made BPA will seek input from customers and stakeholders regarding how to credit FY 2010 savings toward the conservation adjustment.

7.2.6 Low Density Discount

Springfield Utility Board (SUB) states that continuation of the Low Density Discount (LDD) would provide a disincentive for customers to pursue conservation that would otherwise be cost-effective. TRM0008 at 2. SUB is a party of right and therefore ineligible to avail itself of the participant comment provisions of BPA’s *Procedures*. However, BPA will respond to the

concerns. SUB requests that the final TRM include language that requires participants in the LDD program to pursue cost-effective conservation. SUB proposes that the cost-effectiveness test be based on the scenario as if they did not receive the LDD. Alternatively, SUB requests that BPA include the LDD as a specific item that can be re-opened in the TRM at the request of any customer. *Id.*

The design and application of the LDD, and how the LDD will function under tiered rates, will be developed in each rate case that implements the TRM and will appear in the General Rate Schedule Provisions (GRSPs). The implementation provisions of the LDD are not at issue in this proceeding.

7.2.7 Irrigation Rate Mitigation

SUB requests that the GRSPs clearly state that BPA (and not the customer or other entity) determines what “cost-effective” conservation is and that the GRSPs state that if the cost-effective conservation is not implemented within a timely manner, that the Irrigation Rate Mitigation Product (IRMP) will be discontinued for the individual customer. TRM0008 at 2.

The design and application of the Irrigation Discount, and how the Irrigation Discount will function under tiered rates, will be developed in each rate case that implements the TRM and will appear in the GRSPs. The implementation provisions of the IRMP are not at issue in this proceeding.

Lower Valley Energy expresses concern with the design of the IRMP. TRM0005 at 1-2. Lower Valley states that the IRMP is unjustified, is not consistent with cost causation principles, and is not fair to the BPA customers that have to pay higher costs due to the TRM. *Id.* at 2.

BPA notes that Lower Valley Energy is a party to this proceeding and is therefore ineligible to avail itself of the participant comment provisions of BPA’s *Procedures*. However, BPA will respond to Lower Valley’s concerns. The IRMP described in the TRM was determined in BPA’s RD Policy. As stated in the RD Policy, beginning with the FY 2012 rate period the IRMP will be proposed in each rate case as a fixed discount. Contracts offered pursuant to Regional Dialogue state that the IRMP is subject to the terms specified in BPA’s Wholesale Power Rate Schedules and GRSPs. Eligibility for the IRMP will be limited in order to limit the costs that must be reallocated to other customers. The qualification criteria were set to limit eligibility for the IRMP to utilities that have a significant amount of irrigation load. BPA analyzed the rate impact to utilities with large summer loads when compared to utilities with large winter loads, and results were inconclusive. Eligibility for the IRMP is limited, to minimize the cost of the discount, because the discount increases rates for all customers. The qualification criteria were set to recognize those utilities with large irrigation loads that are critical to rural and agricultural-based economies. Because the policy direction to offer the IRMP was established in the RD Policy and will be addressed in the applicable rate cases, the TRM does not deal with implementation provisions of the Irrigation Discount, and thus Lower Valley’s concern is not at issue in this proceeding.

8.0 National Environmental Policy Act Compliance

BPA has evaluated the potential for environmental effects related to the TRM, consistent with the National Environmental Policy Act (NEPA) 42 U.S.C. § 4321 *et seq.* The TRM provides for a two-tiered PF rate design applicable to requirements firm power service and establishes the methodology by which costs of service associated with the existing Federal system (Tier 1) and costs associated with additional amounts of power needed to serve the remaining portion of customers' net requirements (Tier 2) will be determined and implemented. The RHWL that will be determined according to the TRM will be 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 RHWL, limited by its net requirement, at Tier 1 Rates. To meet its above-RHWL net requirement, a customer may either purchase Federal power (at a PF Tier 2 rate(s)) or purchase non-Federal power.

The TRM represents the implementation of a policy for tiering PF rates that was established in BPA's Long-Term Regional Dialogue Policy and evaluated under NEPA in the NEPA ROD for the Policy. The TRM carries out this already-adopted policy by establishing a tiered rate design that differentiates between Tier 1 cost of service and Tier 2 cost of service, and by providing a methodology for calculating each utility's CHWM as well as PF Tier 1 and Tier 2 rates. These basic design and methodology components are generally consistent with the policy for tiering PF rates as described in the RD Policy. The TRM also will be implemented to further certain goals of the RD Policy, such as supporting renewable resources and conservation. The NEPA ROD that was prepared for the RD Policy included an evaluation of tiered rates and their potential environmental impacts. RD Policy NEPA ROD at 14 and 17-20.

A tiered rate structure also was considered in BPA's Business Plan Environmental Impact Statement (DOE/EIS-0183, June 1995). This EIS describes potential options for structuring a tiered rate design. Business Plan EIS, sections 2.3.1.2 and 2.4.2.1 and Table 2.4-1; *see also* Business Plan EIS Appendix B: Rate Design. The Business Plan EIS identifies and discusses market responses that could result from implementation of tiered rates, as well as potential environmental impacts. Business Plan EIS, sections 2.6.2.3, 2.6.3.2, and 4.4. The Market-Driven alternative in the Business Plan EIS, which was adopted by BPA in its Business Plan ROD (August 15, 1995), includes the establishment of tiered rates for firm requirements power in the long term. Business Plan EIS, section 2.2.3. A load-based tiered rate design module is intrinsic to the Market-Driven alternative, and a resource-based tiered rate design also could be implemented under this alternative. Business Plan EIS, Table 2.3-2. Therefore, the TRM falls within the scope of the Market-Driven Alternative that was evaluated in the Business Plan EIS and adopted in the Business Plan ROD.

Finally, the actions that BPA will take to implement the TRM are largely administrative in nature. These actions primarily involve calculations of each utility's CHWM and RHWL, and Tier 1 and Tier 2 Rates. As such, implementation of the decisions related to the TRM in this ROD would not be expected to result in environmental effects.

To the extent that implementation of the TRM could result in changes in consumer or utility behavior and thus indirect environmental effects, these potential changes were considered in the

Business Plan EIS and RD Policy NEPA ROD. As discussed in these documents, tiered rates likely would provide an economic incentive for customers to pursue further conservation measures, which would lessen the potential for environmental impacts such as air emissions and water pollution from generation resources. In addition, any potential shifts to non-Federal power by customers as a result of the Tier 2 Rate would not be expected to result in significantly different environmental effects from a non-tiered rate design. While there could be some pressure to develop additional resources as a result of this shift, it is uncertain what type of resources ultimately would be developed. Although more traditional resources such as combustion turbines (CTs) or coal-fired plants could be developed (with associated environmental impacts), it is more likely that “clean” resources such as wind and solar would be pursued, given the projected growth of these resources in the region, the establishment by several states of renewable portfolio standards, and concerns over greenhouse gas emissions from more traditional resources. Some customers may choose to make market purchases to fulfill their above-RHWM net requirements; this power would be expected to come largely from already-operating existing resources, and therefore would not result in any new or additional environmental impacts. Finally, it is expected that many of BPA’s customers may purchase Federal power from BPA to meet all of their net requirements (i.e., both the amount of power they are entitled to purchase at Tier 1 Rates and their Above-RHWM Load), which would result in no change environmentally from how BPA provides power to these customers. Based on these considerations, even if there is some additional resource development resulting from the TRM and the Tier 2 Rate(s), the potential overall change in environmental effects that could occur under the TRM in comparison to a non-tiered rate design would be expected to be negligible.

Thus, the TRM is an implementation of an already-adopted policy concerning tiered rates, with little to no environmental impact. This implementation is consistent with the Market-Driven Alternative that was evaluated in the Business Plan EIS and adopted in the Business Plan ROD, as well as with the RD Policy and its associated NEPA ROD. Any potential environmental effects related to changes in consumer or utility behavior from the TRM have already been considered and evaluated in prior NEPA documentation.

9.0 Conclusion

The rate methodology established and adopted in this ROD has been set to establish a tiered Priority Firm Power rate that will meet all BPA statutory ratemaking requirements, including, among others, to recover the costs associated with the acquisition, conservation, and marketing of electric power; to amortize the Federal investment in the FCRPS (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years; to recover all other power-related costs and expenses incurred by the Administrator in carrying out the requirements of the Northwest Power Act and other provisions of law; and to recover costs in accordance with sections 7(b)(1) and 7(e) of the Northwest Power Act. In addition, this rate methodology has been designed to set rates as low as possible consistent with sound business principles, to encourage the widest possible use of BPA's power, and to satisfy BPA's other ratemaking obligations. The Hearing Officer has assured me that all interested parties and participants were afforded the opportunity for a full and fair evidentiary hearing, as required by law.

BPA evaluated this proposed rate methodology in a section 7(i) proceeding pursuant to the Northwest Power Act. BPA also evaluated the potential environmental impacts of the proposed rate methodology and alternatives thereto, as required by NEPA. In this instance, the environmental analysis provided by the Business Plan Final EIS details the environmental impacts of BPA's Tiered Rate Methodology. The environmental analysis contained in the Business Plan Final EIS has been considered in making the decisions in this ROD.

Based upon the record compiled in this proceeding, the decisions expressed herein, and all requirements of law, I hereby adopt the Tiered Rate Methodology attached hereto (TRM-12-A-02) as the final Bonneville Power Administration Tiered Rate Methodology.

Issued in Portland, Oregon, this 10th day of November, 2008.

/s/ Stephen J. Wright
Administrator and
Chief Executive Officer
Bonneville Power Administration

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