PACIFIC NORTHWEST INVESTOR-OWNED UTILITY COMMENTS ON LONG-TERM BPA REGIONAL DIALOGUE POLICY ISSUES

October 31, 2006

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EXECUTIVE SUMMARY

The patience that BPA has displayed and the amount of effort that BPA has expended in developing a long-term proposal for BPA's power supply role have been commendable. The PNW Investor-Owned Utilities[1] appreciate this opportunity to comment and look forward to working with BPA to develop its long-term policy. In many respects, BPA's Long-Term Regional Dialogue Proposal ("BPA's Proposal") contains policy and business practice recommendations that are fundamentally sound, such as moving to a BPA tiered-rate structure.

In contrast to BPA's public power utilities, which benefit from the federal hydroelectric system primarily[2] through their preferential access to low-cost federal power, our residential and small farm customers[3] share in the value of the federal hydroelectric system through the Residential Exchange Program ("REP")—typically receiving bill credits instead of megawatts.[4] Under the current REP settlement agreements, BPA pays approximately $300 million per year to the over six million consumers served by the region's investor-owned utilities (about 60 percent of the region's consumers). Compared with the market value of low-cost federal power received by BPA's preference utilities, this REP settlement amount represents only about 18 percent of the total annual benefits produced by the Federal Columbia River Power System ("FCRPS").[5] As a result, we are disappointed that BPA has proposed a settlement of the REP that is less than the amount that our customers currently receive, less than the amount that our customers have received historically and less than the amount we believe our customers are entitled to under the law. This aberration is compounded by the fact that BPA's Proposal simultaneously recommends increasing the capacity of the Federal Base System ("FBS"), which will give the region's public power utilities even greater access to low-cost federal power—at the same time that BPA is proposing to limit our customers' access to the FBS by a reduction in the REP settlement.

BPA's implementation of REP has been the source of contentious litigation for the past 25 years. BPA's analysis of possible ranges of REP levels is a direct function of the agency's

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[1] These comments are submitted on behalf of Avista Corporation ("Avista"); Idaho Power Company ("IPC"); NorthWestern Energy ("NWE"); PacifiCorp; Portland General Electric Company ("PGE"); and Puget Sound Energy, Inc. ("PSE") (collectively, "PNW Investor-Owned Utilities").

[2] BPA's preference utilities are also entitled to participate in the REP.

[3] References in these Comments to our "residential customers" also includes our small farm customers.

[4] BPA has previously recognized the importance of providing REP benefits to the residential and small farm consumers of the PNW Investor-Owned Utilities. *See* 70 Fed. Reg. 7,489 at 7,495 (Feb. 14, 2005).

[5] Market prices are currently higher than when this percentage was calculated. If the percentage were calculated today, it would be even smaller.

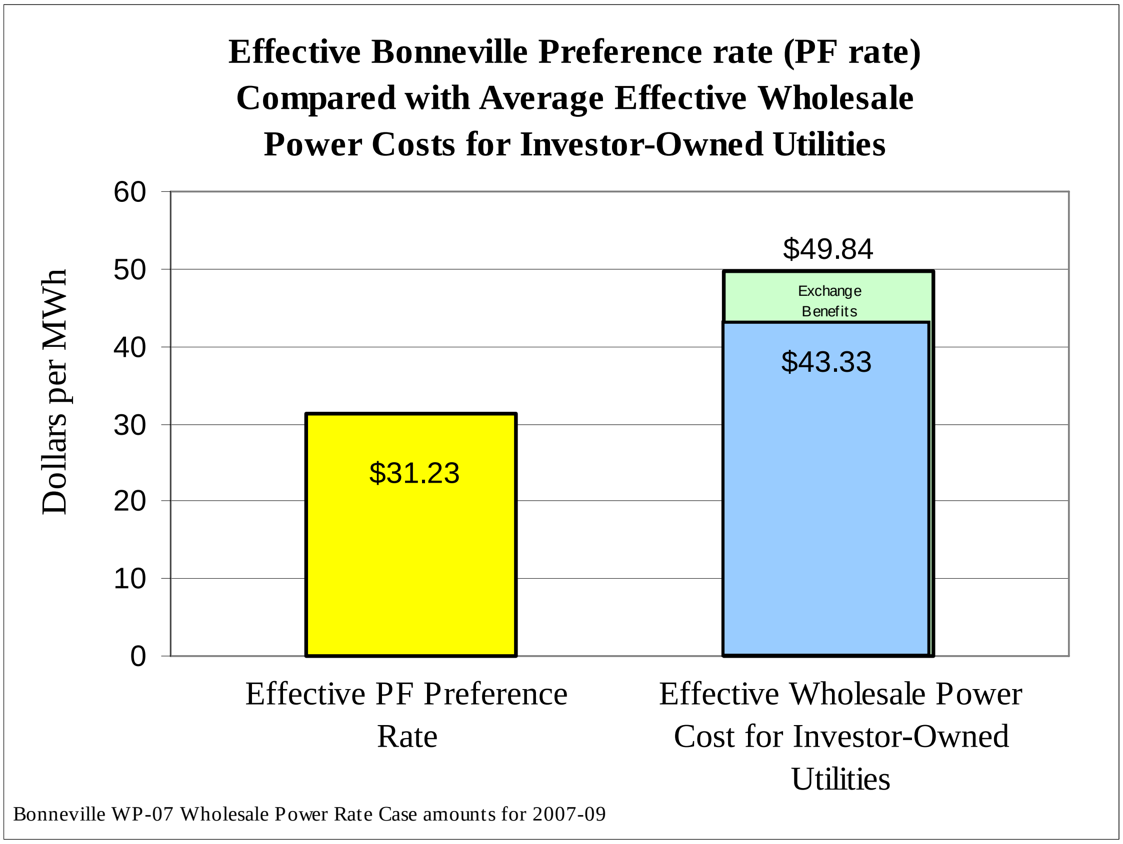
interpretations of the Northwest Power Act.[6] For example, the Administrator's Letter to the Northwest Public Utility Commissioners, dated September 7, 2006 ("Administrator's Letter") states that BPA's current forecast of the REP is less than the current level of REP settlement payments. However, this view rests upon disputed interpretations and assumptions, which were resolved or rendered moot by the current REP settlement agreements for their duration. The Administrator's Letter only underscores the range of REP levels that may result, depending on the assumptions and interpretations used. For example, the PNW Investor-Owned Utilities have estimated that REP levels determined in accordance with the Northwest Power Act would, making reasonable assumptions, be $600 million or more annually for the period commencing with FY 2012. Similarly, the PNW Investor-Owned Utilities have estimated that correcting REP determinations with respect to section 7(b)(2) alone would result in annual REP benefits for their customers in excess of $350 million currently and in excess of $520 million in FY 2013.[7]

Like the BPA Administrator, the PNW Investor-Owned Utilities strongly favor an REP settlement and agree that the level of REP payments is a "crucial issue" for the Regional Dialogue. Further, we agree with the Administrator that durability and sustainability are critical elements of a REP settlement.

As the Administrator's Letter notes, the intent of the Act is to decrease the equity gap between the region's public power and investor-owned utilities by seeking to equalize between the wholesale power costs for the two classes of utilities. Under BPA's Proposal, the equity gap in wholesale power costs between BPA's customer classes would be even greater than it is now. Indeed, the following figure shows that the effective PF Preference rate is substantially lower than the average investor-owned utility Average System Cost ("ASC"), even when the average investor-owned utility ASC is reduced by average investor-owned utility REP benefits:

[6] Pacific Northwest Electric Power Planning and Conservation Act, Pub. L. No. 96-501, 94 Stat. 2697, 16 U.S.C. §§ 839-839h (1980) (the "Northwest Power Act" or "Act").

[7] See Appendix B, pages 9-10.



Under BPA's Proposal, beginning in FY 2012, annual REP settlement amounts would be reduced to $250 million. Adjusted for inflation and load growth, BPA's proposed level of REP Settlement benefits represents an annual reduction of $100 million in bill credits to our residential customers from current levels.

The REP is intended to equalize wholesale power costs, but the impact of BPA's Proposal would be felt at the retail level by our more than six million residential and small farm customers, because their bills would increase as a result of BPA's decision. This adverse impact is inconsistent with the effect of BPA's rate decisions on the residential customers of public power utilities, who are expected to see rate decreases as a result of BPA's recent rate reductions.

One of the most important benchmarks in evaluating the various aspects of BPA's Proposal is how these decisions affect the flow of benefits from the federal system to the region's electricity consumers. BPA has not struck the right balance of regional equity—despite its ability to do so consistent with the law. A long term policy that recommends an increase in the size of the federal power system for BPA's public power utilities—including a generous set-aside for public power utilities that have yet to be formed—while simultaneously recommending an REP level for our residential customers that is below current and historical levels and that is inconsistent with the intent of Northwest Power Act, is not equitable. If it is to be sustainable, BPA's Regional Dialogue Policy should be built upon a foundation of regional equity and the law. Both require that any REP settlement be more robust than that which BPA has proposed.

From a financial perspective, BPA can provide the REP benefit level required by equity and law. In that regard, BPA's Proposal contains opportunities to reduce projected costs. For example, BPA should revisit its proposal to earmark 250 aMW (and to augment the FBS as needed up to the full 250 aMW) of Tier 1 or lowest priced BPA power for newly formed public power entities. BPA also proposes to augment the FBS by up to 300 aMW to supplement the initial High Water Marks ("HWM") of its public power customers. These proposals to provide additional service to public power customers might be acceptable in the context of an overall comprehensive settlement, but are not reasonable in the absence of a REP settlement that meets the requirements of equity and the law.[8]

One threshold question for judging any proposed long-term BPA policy is whether that policy supports the preservation of the value of the existing FCRPS for the region. A durable long-term policy that seeks to preserve the FCRPS for the region must ensure that the value of the FCRPS is equitably distributed throughout the region. The Northwest Power Act makes the benefits of the FCRPS[9] available to all of the region's residential and small farm consumers, whether such consumers are served by preference or investor-owned utilities. Ensuring an equitable distribution of the FCRPS is critical to retaining these benefits within the region for current and future generations. BPA should therefore distribute these benefits, equitably and consistent with the Act, in a manner that aligns the interests of the residential and small farm consumers throughout the region and does not unfairly discriminate against consumers based upon the ownership structure of their local electric utility.

In summary, BPA should take the following three steps[10]:

(i) limit the firm power sales made to firm requirement loads at its lowest cost-based rate to the firm capability of the existing FBS;

(ii) charge a higher tiered rate(s) that reflects the full cost of resources acquired to provide service to firm power loads in excess of the existing FBS capability; and

(iii) offer to the investor-owned utilities for the benefit of their residential and small farm customers an REP settlement that is consistent with the law and that provides an equitable and durable share of the value of the existing FBS.

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[8] Further, as discussed in section E, BPA proposes to spend as much as $16 million per year to provide transfer service for new publics, annexed load and delivery of non-federal power. BPA should not make these expenditures in any case.

[9] The existing federal system consists of the electricity produced by the federally owned hydroelectric dams on the Columbia River and Snake River systems, as well as the output of Energy Northwest's Columbia Generating Station (formerly known as WPPSS Plant No. 2) and other long-term resources that have been acquired by BPA and that are currently in operation or under development.

[10] Any augmentation or increased access to the FBS for BPA's preference utility customers should only be part of a comprehensive settlement that addresses items (i), (ii) and (iii).

Unfortunately, BPA's Proposal fails to provide an equitable share of the existing FBS to our residential and small farm customers. To remedy this, the PNW Investor-Owned Utilities propose that BPA modify the BPA Proposal as described below to provide an equitable level of REP benefits. In the alternative, BPA should provide for our customers a level of REP settlement benefits that equals the amount by which the market price of power exceeds BPA's lowest cost-based rate multiplied by 2,200 aMW, but subject to a cap and floor that equal $350 million and $100 million, respectively, in 2012 dollars, and that are adjusted annually thereafter for relative changes in resource costs or some other measure of inflation.[11]

Taking the three steps set forth above will provide BPA customers increased certainty over their load service obligations—thereby facilitating their ability to meet those obligations, help align the interests of BPA and its customers, help reduce BPA's risk profile, and strengthen BPA's ability to make its Treasury payment in full and on time. Residential and small farm consumers throughout the region will have a stake in preserving the benefits of the low-cost FBS for the region.

In addition, BPA must update and revise the manner in which REP benefits are determined—for example, revise the ASC Methodology, the 7(b)(2) rate step approach and methodology, and the approach for determining the net requirements of utilities participating in the REP.

BPA's schedule for adopting its long-term tiered rate methodology by October 2007 and entering into new long-term contracts by April 2008 is challenging, but also realistic and appropriate. BPA's tiered rate methodology should be applied to all new BPA obligations for service after it is adopted.

I. BPA'S PROPOSAL

A. Service to Publics

1. BPA Should Adopt a Long-Term Tiered Rate Methodology

The PNW Investor-Owned Utilities support limiting BPA's sales of its lowest cost-based rate firm power to its preference utility customers to the firm capability of the existing FBS. Further, the PNW Investor-Owned Utilities agree with BPA's overall framework of establishing a high water mark or HWM to distinguish between Tier 1 rates (for lowest-cost firm requirements power available from the existing Federal system) and Tier 2 rates (for incremental resources).

This approach will reduce the risk that BPA will be overcommitted in the future and will help BPA control the costs of future power purchases by defining the rights to purchase the firm output of the FBS. This approach, if properly designed, will facilitate planning and development of cost-effective generating resources and conservation to meet load in the region by providing

[11] Other settlement valuation mechanisms may be possible but should provide REP benefits that are consistent with the law and that provide an equitable and durable share of the value of the existing FBS.

greater certainty as to the load BPA will meet with the low-cost existing FBS resources. Resources can best be planned in the region if BPA's customers (i) have a clear understanding of the long-term rate structure under which BPA will provide power to serve their loads and (ii) BPA's long-term rate structure provides for the sale of BPA power to meet incremental loads at the full cost of the incremental resources that BPA must acquire to serve new load.[12]

2. BPA Should Not Delay Development or Adoption of a Long-Term Tiered Rate Methodology

BPA has proposed to establish a long-term tiered rate methodology by October 2007, and this schedule should not be delayed.[13] BPA's customers need greater clarity about their federal power supply so that they can plan effectively for the future and make long-term power supply commitments. Successful resource planning is a long-term process that requires long-term BPA policy clarity. Timely adoption of a durable BPA tiered rate methodology is fundamental to BPA's implementation of successful long-term initiatives.

BPA should incorporate its long-term tiered rate methodology into all new obligations for service that BPA enters into after such methodology is adopted. For example, BPA should apply this rate methodology to new publics and annexed investor-owned utility load following the adoption of a tiered-rate methodology. Any loads subject to the targeted adjustment clause ("TAC") mechanisms at such time should be moved to the Tier 2 rate. This will help carry out BPA's established policy direction of limiting its firm power sales at the lowest cost-based rate to roughly the firm capability of the existing FBS.

3. BPA's Long-Term Tiered Rate Methodology Should Be Adopted, and Confirmed and Approved by FERC, Under Section 7 of the Northwest Power Act

BPA should develop and adopt a tiered rate methodology in a proceeding under section 7(i) of the Northwest Power Act. The adoption would be accomplished by a BPA final action that is subject to confirmation and approval by FERC.[14]

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[12] This approach is also consistent with "Recommendations for Executive Action" at page 38 of the July 2004 GAO Report.

[13] Delaying the implementation of such a methodology increases BPA's exposure to costs and risks such as those experienced when it faced a power supply deficit during the West Coast electricity crisis of 2001.

[14] There is precedent for BPA's long-term adoption of such a rate methodology. For example, BPA in 1987 adopted the IP-PF Rate Link Methodology in a proceeding under section 7(i) of the Northwest Power Act. *See* 51 Fed. Reg. 24197, 24199 (July 2, 1986). FERC confirmed and approved extension of that methodology on February 3, 1992, noting that "since the IP-PF Rate Link Methodology provides Bonneville with load planning certainty and its DSIs customers with rate predictability, both positive attributes, the requested extension of the IP-PF Rate Link Methodology is approved." 58 FERC ¶ 62,101 (Feb. 3, 1992). Thus, a long-term BPA rate methodology has been previously confirmed and approved by FERC. Moreover, in approving such methodology, FERC noted that BPA load planning certainty and BPA customer rate predictability are positive attributes.

4. BPA's Proposal To Augment The Federal System For Its Preference Utility Customers Should Only Be Adopted in the Context of a Broad Settlement[15]

BPA's Proposal contemplates augmenting the FBS for its preference utility customers as follows:

(i) up to 250 aMW of firm power at Tier 1 rates for new publics, and

(ii) up to 300 aMW of firm power at Tier 1 rates to supplement the initial HWMs of BPA's public power utilities.

BPA's stated goal at page 12 of BPA's Proposal is to limit "BPA's costs, rates, and risk by not diluting the low-cost Federal system with high-cost power purchases." Absent a broad regional settlement of the REP and other Regional Dialogue issues, BPA's planned augmentation of the FBS would severely undermine BPA's stated goal.

The PNW Investor-Owned Utilities acknowledge that such accommodations to augment the FBS may be appropriate given the larger goals of BPA's proposal—but only in the context of a broad regional settlement that addresses the equitable concerns of all of BPA's customer classes, not just the public power and direct service industrial customer classes. BPA's Proposal should not incorporate any of these deviations from BPA's goal of limiting costs and risk, including service to new public power entities and augmentation to supplement initial HWMs, except as part of an overall package under Regional Dialogue contracts for which there is a regional consensus and which includes a durable REP settlement that provides for equitable REP benefits to the residential and small farm customers of the region's investor-owned utilities.

BPA's Proposal contemplates permitting the removal of some 312 aMW associated with the Centralia Coal Plant from dedication to serve load by four preference customers and working with the region to see if BPA can accommodate the request for such removal "as a part of an overall package for service under Regional Dialogue contracts."[16] Any such removal should only be permitted in the context of a broad settlement and should not result in augmentation of the

[15] Augmentation of the FBS for BPA's preference utility and direct service industrial customers should be addressed only in an overall policy that ensures the equitable distribution of value of the existing federal system to all residential and small farm customers in the region in accordance with the intent and provisions of the law.

[16] BPA's Proposal states as follows at page 18:

> Prior to the start of the Subscription contracts the Centralia Coal Plant was sold to an extra-regional party. Four public utilities--Seattle, Tacoma, Snohomish PUD, and Grays Harbor PUD–were part owners of the project prior to the sale. Since this resource had been dedicated to serve regional load under their Subscription contracts, BPA required that these customers replace this resource. BPA intends to work with the PPC and the rest of the region to see if it can accommodate the PPC's Proposal as a part of an overall package for service under Regional Dialogue contracts. BPA proposes to conduct a review of the Centralia sale under its 5(b)/9(c) policy. However, BPA would need to collect, review, and determine the facts and the circumstances of the customers' sale of the Centralia resource. BPA would ultimately need to review the facts and determine whether it can sell firm power or only surplus power as a replacement for the Centralia resource under section 9(c) of the Northwest Power Act.

FBS in addition to the 300 aMW to supplement the initial HWM of BPA's preference utilities. Such additional augmentation would be inconsistent with BPA's fundamental objectives in establishing tiered rates.

B. REP Settlement Proposal

1. A Long-Term Settlement of the REP Must Be Durable and Sustainable

Like BPA, the PNW Investor-Owned Utilities favor settlement of the REP to the extent such a settlement provides certainty and durability. A settlement can provide a higher degree of "certainty" by establishing a defined REP level that adjusts according to a transparent and objective mechanism. A settlement can provide durability if it provides an equitable disposition of BPA's legal obligation to provide a share of the federal hydro system to the 60 percent of the region's citizens that receive electricity service from investor-owned utilities. We agree with BPA that "it is very important that a settlement of the REP be durable and sustainable over time."

2. The Level of REP Settlement Payments Offered By BPA Is Much Lower Than Would Be Produced Under A Properly-Implemented REP

BPA's estimated range of REP levels is too low because of BPA's erroneous legal interpretations and assumptions regarding the REP. The PNW Investor-Owned Utilities have estimated that correcting REP determinations with respect to section 7(b)(2) alone would result in annual REP benefits for their customers in excess of $350 million currently and in excess of $520 million in FY 2013. With the addition of a corrected ASC methodology and updated ASCs, REP levels determined in accordance with the Northwest Power Act would be $600 million or more annually for the period commencing with FY 2012.[17] ASCs should generally reflect the increasing costs associated with factors such as hydro relicensing, resource acquisition, increases in emission regulation and fuel costs. Each of the PNW Investor-Owned Utilities is forecasted to have an ASC greater than BPA's PF Exchange rate for the period commencing with FY 2012. In the past, some believed that one or more PNW Investor-Owned Utilities had low ASCs that would make them ineligible to participate in the REP during the period commencing FY 2012—but any such belief simply does not reflect the reality of increased costs faced by all PNW Investor-Owned Utilities.

BPA's proposed REP settlement benefits are based on BPA's erroneous conclusion at page 48 of BPA's Proposal "that the 7(b)(2) rate test would limit benefits under the REP to the range of $250-$300 million." As recognized in BPA's Proposal at page 46, BPA's analysis only "examined the uncertainty created by one disputed legal interpretation [regarding Mid-Columbia resources] and several factual uncertainties." Examples of 7(b)(2) rate step issues that must be

[17] *See,* Pacific Northwest Investor-Owned Utility Comments on Long-Term BPA Regional Dialogue Policy Issues, dated June 13, 2005. *Cf.*, the PNW Investor-Owned Utilities's estimate in 2002 that REP benefits for FY 2007-2011 determined in accordance with the Northwest Power Act would be approximately $400 million per year.

taken into consideration in determining or evaluating the potential effect of that rate step on the benefits that should be provided under the REP include the following (which are discussed in Appendix B):

a. **Conservation.** In the 7(b)(2) Case, BPA must avoid two related errors with respect to conservation. First, BPA cannot ignore load reductions achieved through conservation. Second, BPA cannot ignore substantial conservation costs actually incurred by BPA. The Northwest Power Act neither requires nor allows BPA to ignore these load reductions achieved and costs incurred.

b. **Mid-Columbia Resources.** In the 7(b)(2) Case, BPA must avoid the following errors:

   i. including Mid-Columbia resources in the 7(b)(2) Case resource stack that are not, in fact, "owned . . . by public bodies or cooperatives";

   ii. including Mid-Columbia resources in the 7(b)(2) Case resource stack that are, in fact, "committed to load pursuant to section 5(b)" of the Northwest Power Act; and

   iii. understating costs for Mid-Columbia resources drawn from the 7(b)(2) Case resource stack in determining the projected amounts to be charged in the 7(b)(2) Case (assuming for the sake of argument that such resources were owned by public bodies or cooperatives, were not committed to load pursuant to section 5(b) of the Northwest Power Act and could be included in the 7(b)(2) Case resource stack).

c. **Value of Reserve Benefits.** In the 7(b)(2) Case, BPA must avoid the error of ignoring the substantial reserve benefits provided by BPA's surplus sales in the wholesale power market. BPA cannot assume that it receives reserve benefits only from power sales to Direct Service Industrials ("DSIs"). In fact, the reserve benefits provided by BPA power sales in the wholesale power market are superior to those provided by power sales to DSIs.

d. **Costs of Terminated WNP-1 and WNP-3.** BPA must avoid the error of failing to subtract from the Program Case, as section 7(g) costs of uncontrollable events, BPA's costs of the terminated WNP-1 and WNP-3. The fact that BPA made a measured, rational response to an uncontrollable event does not and cannot render controllable events such as the Supply System's inability to finance.

e. **Costs of Financial Reserves for Risk.** BPA must avoid the error of failing to subtract from the Program Case, as section 7(g) costs of uncontrollable events, any of the Financial Reserves for Risk held by BPA as risk mitigation funds in order to mitigate the impacts of operating and non-operating risks.

f. **Costs of PNRR.** BPA must avoid the error of failing to subtract from the Program Case, as section 7(g) costs of uncontrollable events, the Planned Net Revenues for Risk ("PNRR"), which BPA includes in its revenue requirement in order to mitigate the impacts of operating and non-operations risks.

g. **<u>Allocation of Specified Amounts Charged Under Section 7(g)</u>.** BPA must avoid the error of failing to subtract from the Program Case the proper amount of conservation and other specified section 7(g) costs because BPA has failed to properly allocate such costs.

BPA's conclusion "that the 7(b)(2) rate test would limit benefits under the REP to the range of $250-$300 million" was based on an analysis that recognized only the issue with regard to Mid-Columbia resources and that apparently fails to address and correct each of the errors identified above.

As discussed below and in Appendices A and B, properly-determined annual REP benefits for the residential and small farm customers of investor-owned utilities should be $600 million or more annually for the period commencing with FY 2012. Similarly, the PNW Investor-Owned Utilities have estimated that correcting REP determinations with respect to section 7(b)(2) alone would result in REP benefits for their customers in excess of $350 million currently and in excess of $520 million in FY 2013.

3. BPA's Proposed REP Settlement Amount Would Represent a Substantial Reduction in REP Benefits for the Residential and Small Farm Customers of the Investor-Owned Utilities

BPA's proposed REP settlement benefits of $250 million for FY 2012 would

(i) reduce the benefits of our customers by about a third in today's dollars compared to current benefit levels,

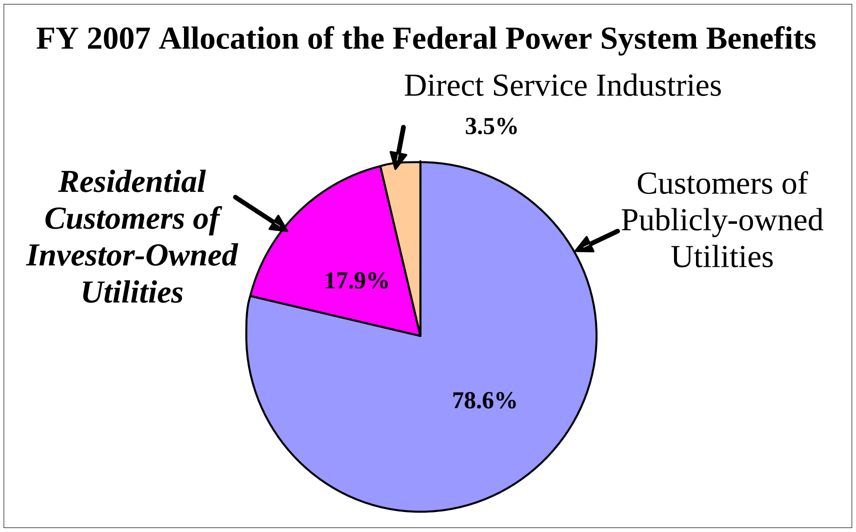
(ii) be significantly less than historical levels when adjusted for inflation and customer growth,

(iii) leave the 60 percent of the consumers in the Pacific Northwest that we serve with only about 12 percent of the FCRPS, and

(iv) provide significantly less value than should be provided under the REP.

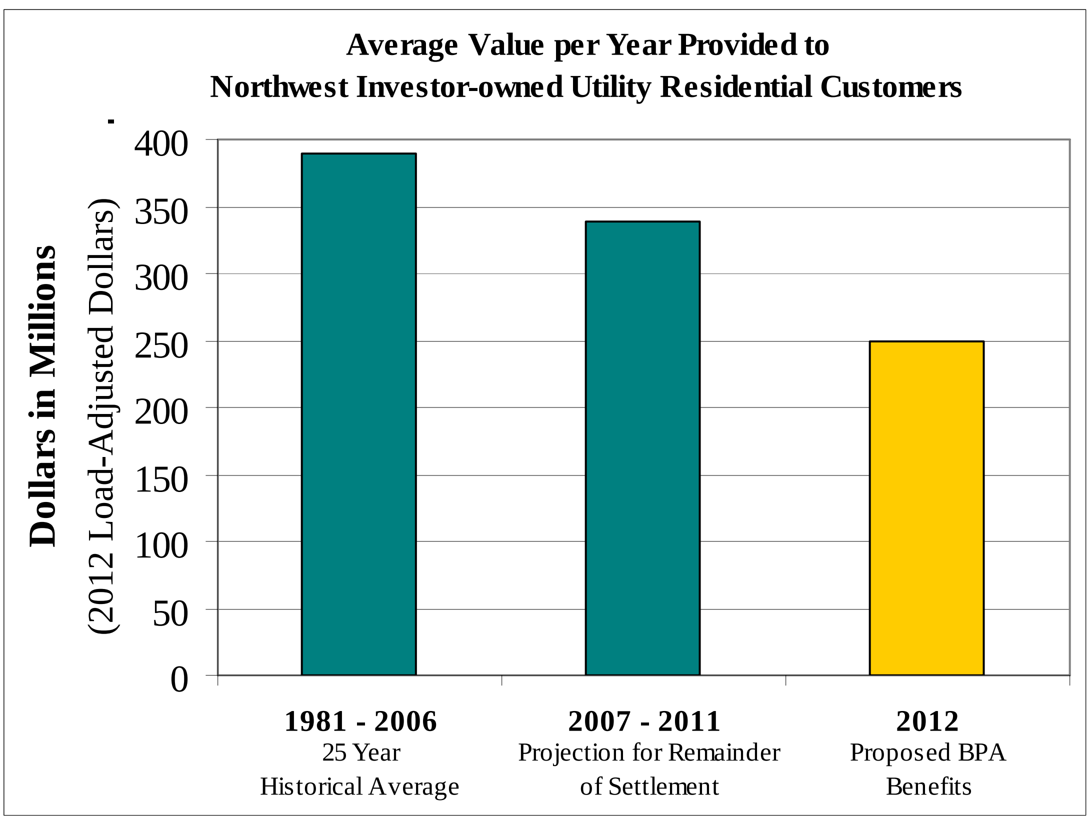
The value of the FBS has increased with the rise in wholesale market prices. BPA's Proposal would decrease benefits to our residential and small farm customers even as BPA is increasing benefits for its public power utility customers by cutting their power rates. This reduction in REP benefits is particularly inequitable in light of the fact that our residential and small farm customers currently receive only about 18 percent (approximately $300 million per year) of the benefits of the FBS. This current allocation of benefits may be illustrated as follows:

FIGURE 1



When adjusted for inflation and customer growth to FY 2012, the historical average annual level of REP benefits for our residential and small customers would exceed $390 million. Similarly, when adjusted for inflation and customer growth to FY 2012, the current (FY 2007-2011) annual level of REP benefits for our customers is almost $350 million.

FIGURE 2



To be consistent with these current and historical benefit levels, BPA should offer an REP settlement of $350 million per year for our residential and small farm customers for FY 2012.

4. BPA's Proposal Widens the Equity Gap Between BPA's Customer Classes By Decreasing REP Benefits to Our Customers While Benefits to Preference Utility Customers Are Increasing

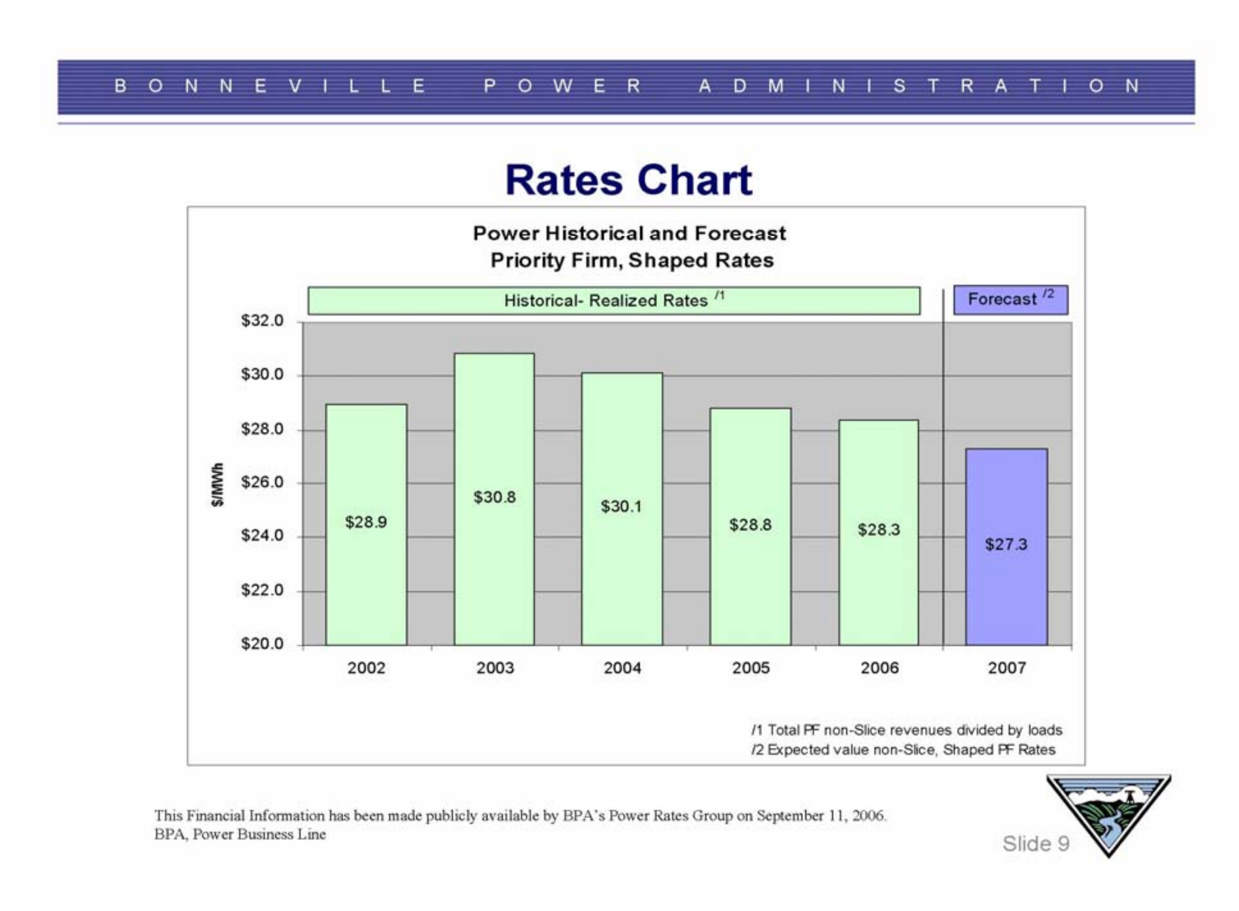
BPA should not increase access to the FBS for other BPA customer classes at the same time it is proposing to reduce the value of the REP for our customers:

(i) up to 250 aMW of firm power at Tier 1 rates for new publics, and

(ii) up to 300 aMW of firm power at Tier 1 rates to supplement the initial HWMs of BPA's public power utilities.

BPA is proposing to increase the access to the FBS available to preference utilities at the same time that BPA preference (PF) power rates have been decreasing:

FIGURE 3



This figure shows that BPA's average rate charged its (non-Slice) preference utility customers has decreased $2.80 per MWh over the last three years, from $30.10 per MWh in FY 2004 to $27.30 per MWh in FY 2007. As compared to BPA rates for FY 2006, the BPA rates for FY 2007 decreased rates by 3 percent for BPA's non-Slice preference customers and by 5 percent for its Slice preference customers.

Again, BPA should not propose a substantial reduction in REP benefits for our customers when BPA is proposing a increased preference utility benefits and BPA's PF rate has been dropping.

5. BPA's REP Settlement Proposal Should Be Modified

This section sets forth a series of modifications to BPA's proposed settlement of the REP. In addition to producing an REP level that satisfies the intent of the Northwest Power Act, our proposed modifications to BPA's Proposal will help the region retain the benefits of the existing FBS, reduce uncertainty for BPA and its customers, and provide a mechanism that maintains equitable relationships between BPA customer classes:

> (i) The base amount, beginning in FY 2012, must be adjusted upward to be consistent with the benefit levels received by our customers during the current settlement period. The PNW Investor-Owned Utilities have recommended a base amount in FY 2012 of $350 million. This base level of benefits is intended to maintain a real share of value of the FBS. Our recommended base funding level also keeps the settled REP value consistent with the value that would be produced by a properly-determined REP.
>
> (ii) The method of annually adjusting or indexing the base amount should be directly responsive to the amount by which the investor-owned utility ASCs exceed the Proxy PF, similar to the mechanics of the REP. BPA's proposed index, which compares ASC and PF as a ratio, rather as a "minus" or delta, severely dampens the adjustment of the base settlement value over time. The result is that even when the difference between ASC and PF increases in nominal dollars, the benefit level produced by the ratio index typically remains flat or increases only slightly. As compared to what ASC minus PF would produce, the BPA Proposal would severely erode the real-dollar value of the REP settlement benefit over time.
>
> (iii) The methods for developing the ASCs for the PNW Investor-Owned Utilities and the Proxy PF for preference utility costs and calculating REP benefits must be transparent, clear and equitable.

6. If BPA Does Not Adopt Our Proposed Modifications To BPA's Proposed REP Settlement, BPA Should Adopt the REP Settlement Proposal Set Forth In Our June 13, 2005 Comments

Alternatively, the PNW Investor-Owned Utilities recommend (as in the current FY 2002-2011 REP settlement) the settlement beginning in FY 2012 be based upon 2,200 aMW.[18] Under this alternative proposal, benefits would be the product of 2,200 aMW multiplied by the amount by which the market price exceeds BPA's lowest cost-based (i.e., Tier 1) rate.[19] The settlement amount should be subject to an annual cap of $350 million and an annual floor of $100 million. This cap and floor would be subject to adjustment annually for relative changes in resource costs and some other measure of inflation. It is anticipated that these payments will be distributed among the PNW Investor-Owned Utilities for the benefit of their residential and small farm customers based on an allocation jointly recommended by the Pacific Northwest State Utility Commissions. *See* Joint Letter of Pacific Northwest State Utility Commissions dated May 26, 2005.

This proposed settlement is based on 2,200 aMW of REP settlement benefits for the PNW Investor-Owned Utilities and the sale of the power from the existing FBS to BPA's preference utilities at Tier 1 rates. The economics and the basic balance sought by this proposal would not be realized if the costs of additional resources (e.g., augmentation of the FBS) or additional REP payments (for REP exchanges by public power) were included in the Tier 1 rate. Such augmentation of REP preference utility benefits would unacceptably dilute the value of our proposal for our residential and small farm customers and would require an adjustment to correspondingly increase the 2,200 aMW REP settlement benefits.

7. The PNW Investor-Owned Utility Proposed REP Settlement Benefits Are Reasonable as Compared With Prior and Current REP Benefit Levels

The following figure illustrates average annual benefits from the existing FBS provided by BPA under prior and current agreements[20] for residential and small farm consumers of the

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[18] The 2,200 aMW is less than one-half of the residential and small farm consumer load currently served by the PNW Investor-Owned Utilities. The PNW Investor-Owned Utilities serve about 4,700 aMW of the 7,800 aMW of regional residential and small farm load. Particularly in light of this, allocating less than 2,200 aMW of benefits of the existing FBS for the residential and small farm consumers served by PNW Investor-Owned Utilities could not be considered equitable.

[19] For example, the proposed benefits would be $350 million with a market price $18.16 greater than the Tier 1 PF rate (e.g., a market price of $48.16 per MWh and a Tier 1 rate of $30.00 per MWh). The proposed benefits would be $100 million with a market price $5.19 greater than the Tier 1 PF rate.

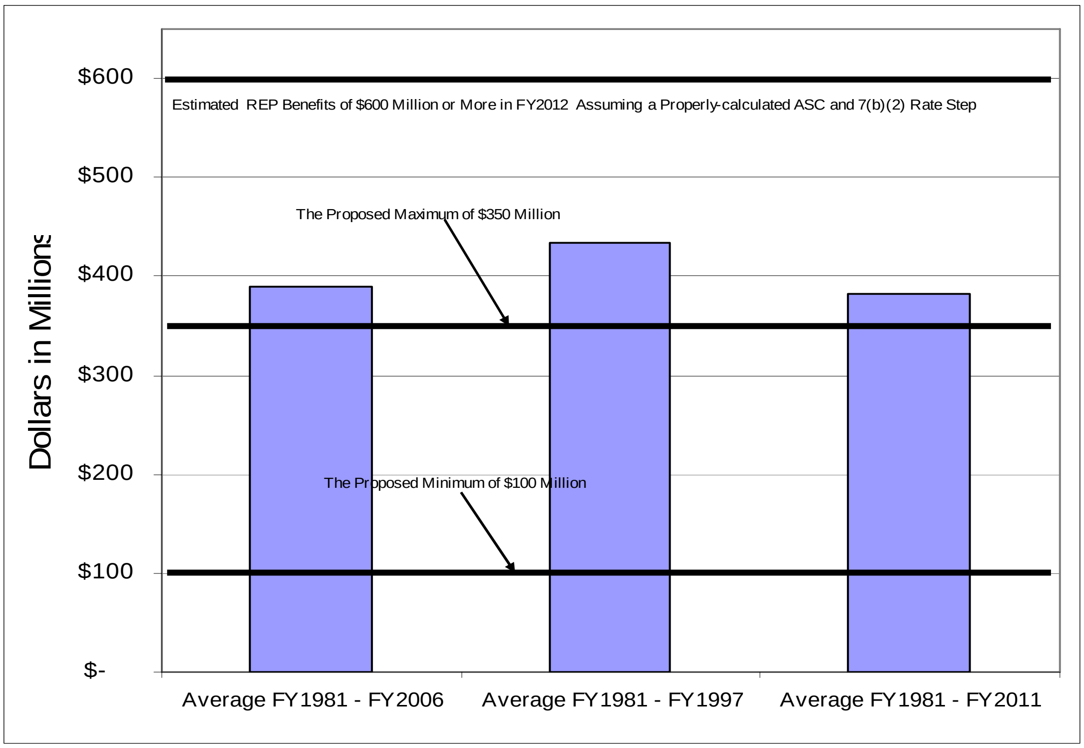
[20] Under the terms of the current REP settlement agreements, PNW Investor-Owned Utilities will receive, for the benefit of their residential and small farm consumers, between $100 million and $300 million per year in monetary payments for the period of FY 2007-2011. These payments are calculated based on the amount by which the market price exceeds the PF rate, multiplied by 2200 aMW. Under the settlements for the period FY 2002-2011, the allocation of payments to each PNW Investor-Owned Utility for its residential and small farm customers was made consistent with the recommendations of the Pacific Northwest State Utility Commissions. In addition, under the terms of the current REP settlement agreements, the PNW Investor-Owned Utilities will receive no firm power during the FY 2007-2011 period.

PNW Investor-Owned Utilities.[21] These historical averages of REP levels for our customers exceed the $350 million cap of our alternative proposal, which suggests that, if anything, the cap in our alternative proposal is too low.

FIGURE 4

BPA Residential Exchange Financial Benefits[22]

Average Value per Year Provided to Residential and Small Farm Consumers of Investor-Owned Utilities
(Amounts prior to 2012 increased to reflect residential customer loads in 2012)
(includes only financial benefits for residential and small farm consumers)
(FY 2007 – FY 2011 at maximum per contracts, without 2003 deferrals)
($millions in 2012 Dollars)



[21] This figure illustrates the average REP level during various periods. This figure reflects financial or monetary benefits only and does not reflect any level of benefits for actual power deliveries under the current agreements.

[22] The REP benefits shown above reflect two adjustments that are necessary to appropriately compare the level of these benefits during various periods:

(i) Adjustment for the effects of inflation by converting all of these benefits to 2012 dollars.

(ii) Adjustment of benefits for years prior to 2012 to reflect what those benefits would have been if provided at the same rate to the residential and small farm customer load in 2012 (i.e., the benefits for any year prior to 2012 are increased by the same percentage as the increase in load between that year and 2012).

Amounts include only financial or monetary benefits for residential and small farm consumers. Amounts for FY 2007-2011 are included at maximum for those years per contracts, without 2003 deferrals.

C. BPA's Service To Direct Service Industries And BPA's New Large Single Load Policy

Under the BPA Proposal, BPA would continue the DSI discussion. In doing so, BPA should consider these comments regarding BPA service to DSIs and BPA's New Large Single Load ("NLSL") Policy, as well as the relationship between these two issues.

BPA's existing NLSL Policy has promoted stability regarding BPA's service for large industrial loads in the region, including the plants, primarily aluminum smelters, of BPA's long-time DSI customers. Generally, a new load of 10 aMW or greater is a NLSL, and the rate for BPA power sold for service by a preference customer to such load is the "Section 7(f)" rate.[23] BPA's NLSL Policy should not (and under the Northwest Power Act cannot) be changed so as to allow a preference utility to purchase power from BPA at the PF (section 7(b)) rate[24] for service to a DSI load of 10 aMW or greater moved to the preference utility's system. BPA service to a local preference utility for such a DSI load at the PF rate would conflict with applicable statutes and BPA's NLSL Policy. It would also increase the uncertainty about the load-serving obligations of both BPA and its preference utility customers.

Sales by BPA at the PF rate for service to such DSIs would provide incentives for such DSI loads to shift to the local preference utility. Such shifts would increase the preference utility's net requirement and would not necessarily decrease (and may well increase) BPA's exposure to costs and risks due to load fluctuations. Such a shift would also eliminate or restrict BPA's ability to directly contract with DSIs for power sales and include in those contracts provisions that seek to mitigate the financial risks of load fluctuations on BPA and its customers.

In any event, any DSI benefits provided by BPA should permit BPA to use DSI stability and other reserves. As stated by the Northwest Power and Conservation Council:

> If power is to be made available to DSIs, the amount and term should be limited, the cost impact on other customers should be minimized, and *Bonneville should retain rights to interrupt service for purposes of maintaining system stability and addressing temporary power supply inadequacy*.

(Emphasis added.)[25] In that regard, all BPA sales to DSIs under section 5(d) of the Northwest Power Act, whether pursuant to their initial long-term contracts or otherwise, are required to provide a portion of BPA's reserves for firm power loads within the region.[26]

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[23] 16 U.S.C. § 839e(f).

[24] 16 U.S.C. § 839e(b)(1).

[25] BPA Short-Term Proposal at 14; 69 Fed. Reg. 43,399, 43,404 (July 20, 2004).

[26] *See* 16 U.S.C. § 839c(d)(1)(A) and § 839c(d)(3).

D. BPA Conservation and Renewables

1. Conservation

BPA should recognize and support the value of working on conservation and renewable efforts with all of the region's utilities, including the investor-owned utilities. BPA's Proposal, however, fails to address the key comment made by the PNW Investor-Owned Utilities on June 13, 2005 ("June 13, 2005 Comments") with regard to conservation—that BPA should continue its Conservation Rate Credit ("CRC") mechanism.[27] BPA's Proposal should be revised to provide for continuation of the CRC mechanism for all of the region's utilities, including the investor-owned utilities under the REP or an REP settlement.[28] More fundamentally, BPA's conservation policy should recognize that, under the REP, BPA is making a sale of firm power under section 5 of the Act. This sale (and any settlement of the REP) should be treated for purposes of BPA's conservation policy like all other BPA firm power sales that BPA is obligated to make under section 5 of the Act.

BPA's "no decrement" policy avoids an undesirable disincentive for conservation and renewable efforts.[29] In that regard, BPA's customers widely note the great success of the C&RD program, which has no accompanying decrement, and widely believe this is money well spent. All of the conservation and renewables covered by BPA's C&RD or CRC should be recognized in evaluating the results of BPA's conservation and renewable efforts against its targets. Therefore, BPA should not penalize regional utilities that implement conservation measures through decrements to loads (e.g., reduction in net requirements), whether in the form of decrements to Block or other purchases, decrements under any BPA REP, or decrements under any REP settlement agreements.[30]

2. Renewable Resources

BPA should address the recommendations of our June 13, 2005 Comments, that BPA continue what is now referred to as its CRC mechanism and associated renewable option.

BPA's proposal to use "facilitation dollars" to support only preference utility efforts to develop renewable resources should be revised to offer these monies to BPA's investor-owned utility customers on the same basis. BPA should not inequitably and artificially restrict the

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[27] Formerly referred to as the Conservation and Renewables Discount.

[28] *See* 16 U.S.C. § 839d(e)(2), which requires that "[t]o the extent conservation measures or acquisition of resources require direct arrangements with consumers, the Administrator shall make maximum practicable use of [BPA's] customers and local entities capable of administering and carrying out such arrangements."

[29] Similarly, for example, BPA's acquisition of resources under the Northwest Power Act must not reduce the Administrator's "efforts to achieve conservation and to acquire renewable resources installed by a residential or small commercial consumer to reduce load, pursuant to [16 U.S.C. § 839d(a)(1)]." 16 U.S.C. § 839d(b)(5).

[30] *See* 16 U.S.C. § 839d(k), which requires that "[i]n the exercise of his authorities pursuant to this [section 6, Conservation and resource acquisition, of the Northwest Power Act], the Administrator shall, consistent with the provisions of [the Northwest Power Act] and the Administrator's obligations to particular customer classes, insure that benefits under this section . . . are distributed equitably throughout the region." The "no decrement" approach is consistent with distribution of the benefits under section 6 of the Northwest Power Act equitably throughout the region.

disbursement of incentives for renewable energy development based on utilities' ownership structure. BPA should offer facilitation dollars to all regional utilities in order to provide the most comprehensive incentives for renewable resource development.

BPA's hope to offer additional wind integration, storage and shaping products, as well as other products and services that may evolve, under long-term contracts, to public power customers should be revised to reflect that such products and services will be made available to BPA's investor-owned utility customers on the same basis. BPA should not inequitably and artificially restrict the availability of such products and services based on utilities' ownership structure.[31] BPA should offer such products and services to all regional utilities in order to facilitate resource development.

BPA is uniquely situated in the region and well-suited to take a leadership role in developing experimental renewable resources. BPA should use its statutory authority to help foster the development of innovative renewable resource technology through credits and acquisitions.[32]

E. BPA Transfer Service

BPA's Proposal includes several proposed resolutions of issues related to BPA's transfer service and the 20-year Agreement Regarding Transfer Service ("ARTS") signed in 2005 with BPA's transfer service customers. The PNW Investor-Owned Utilities recommend that BPA revise its proposals regarding transfer service as described below.

1. BPA Should Not Expand the Transfer Service It Pays For

In general, BPA's expansion of transfer service seems contrary to BPA's goals of cost control. More fundamentally, by masking BPA's costs of new transfer service through melding such costs into the rates also paid by other customers, BPA would not send a proper price signal regarding the costs BPA incurs, contrary to its objective of sending price signals with respect to load growth. BPA should revise its proposal to specify that BPA will not be providing and paying for transfer service beyond that which it is currently providing.[33]

Under BPA's Proposal, BPA would provide "financial support for the transmission of non-Federal energy deliveries under transfer service contracts held by BPA or the customers, under certain conditions." Specifically, preference utility customers would be eligible for

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[31] This is particularly true in light of the FERC Open Access Transmission Tariff Notice of Proposed Rulemaking (May 19, 2006), which indicates that FERC is contemplating the addition of generator imbalance service as a service to be provided under the *pro forma* OATT.

[32] BPA has authority to acquire the output of experimental resources under 16 U.S.C. § 839d(d). Under 16 U.S.C. § 839d(e)(1), "[i]n order to effectuate the priority given to conservation measures and renewable resources under [the Northwest Power Act], the Administrator shall, to the maximum extent practicable, make use of his authorities under [the Northwest Power Act] to acquire conservation measures and renewable resources, to implement conservation measures, and to provide credits and technical and financial assistance for the development and implementation of such resources and measures . . . ."

[33] BPA's Proposal fails to adequately explain the rationale and legal basis upon which BPA would pay for additional transfer service, particularly with respect to delivery of non-Federal power.

financial assistance to offset the transmission costs of purchasing up to 600 aMW of power that, if purchased from BPA, would be sold at a Tier 2 rate. BPA's Proposal at 68. (Such financial assistance would be capped at $16 million for the term of the 20-year Regional Dialogue contract.)

BPA's proposal to pay for delivery of the non-Federal power is motivated by BPA's desire stated at page 68 of BPA's Proposal that "[t]ransfer service should not unnecessarily bias a customer to buy only Federal power to avoid the additional cost of wheeling over third-party transmission facilities." To the extent BPA wishes to achieve this result, it should not do so by paying for additional transfer service (that in our view is a continuation and extension of the effects of BPA's historical treatment of transmission customer that seemed to us to be discriminatory). Rather, if BPA desires even-handed treatment of non-federal and federal power for non-Tier 1 loads, BPA should not pay for transfer service for such loads, regardless of whether they are served with BPA Tier 2 power or with non-federal power. Because the HWMs are anticipated to cover all existing BPA preference customer loads, such a policy will not adversely affect any existing BPA transfer service to existing loads.

In any event, BPA should not pay for transfer service for delivery of non-federal power. Although BPA's Proposal is unclear on this point, its proposal to pay for some amount of transfer service for non-federal power appears also to be motivated by a desire to "provide comparability with directly connected customers." BPA's Proposal at 69. Although providing financial support for non-federal purchases of what would be Tier 2 power for BPA's preference utility customers that are not connected to the FCRTS may appear to place such customers on an equal footing, in one sense, with BPA preference utility customers that *are* connected to the FCRTS, such treatment is not "comparable" in the sense required under the Open Access Transmission Tariff ("OATT") and in fact would unfairly discriminate against BPA transmission customers that are not preference utilities. "Comparability" requires that utilities offer third parties access on the same or comparable basis, and for the same charge, as the transmission provider's own use of its system. Through a policy that is intended to place BPA's power customers on a comparable basis, BPA inadvertently discriminates among its transmission customers by offering a subsidy to preference utility transmission customers, but not to transmission customers that are not preference utilities (e.g., investor-owned utilities).

BPA's Proposal states at page 69 that BPA's OATT provides a mechanism for payment of this subsidy:

> Currently Section 36 of BPA's Open Access Transmission Tariff provides a mechanism for supporting some transfer cost associated with non-Federal deliveries. Section 36 is subject to the outcome of future rate cases or subsequent tariff filings. The decision to cover future costs of non-Federal deliveries under Section 36, or another form of rate treatment, is not part of this proposal and is an issue for future rate cases.

BPA should support the elimination of such a mechanism for paying transfer costs associated with non-federal deliveries, and BPA's Proposal should be revised to indicate that BPA will support such elimination. If it is not eliminated, then customers of a public power utility would benefit from subsidized deliveries of non-federal power, whereas adjacent customers of an investor-owned utility would pay rates that include not only the costs of that utility's delivery but also a portion of the subsidy to the public power utility.

In addition, the following statement in BPA's Proposal at 68 is indefinite, open-ended and fails to justify and explain what is contemplated and the consequences thereof:

> If firm transmission capacity is not available between the third-party transmission system, or the FCRTS, and the customer's load area, BPA may consider other options on a case-by-case basis.

This unexplained statement should be deleted.

2. BPA Should Not Provide Transfer Service for Annexed Load or New Publics

BPA's Proposal recommends providing up to 250 aMW of new transfer service for annexed loads and new preference utilities. BPA's Proposal at 69. This 250 aMW of new transfer service appears to be in addition to the as much as 600 MW of transfer service for non-federal power that BPA proposes to otherwise provide to its preference utility customers. Neither of these BPA transfer service proposals should be adopted.

Under the BPA Proposal, BPA would arrange and pay for up to $7/MWh of financial support for up to 250 aMW of transfer service for annexed loads and new publics. This would be an unjustified and unwarranted subsidy and would be contrary to BPA's objective stated at 69 of BPA's Proposal: "BPA's provision of transfer service should not influence the annexation outcome." Because it would provide financial incentives for annexation of investor-owned service territories, BPA's offer to arrange and pay for transfer service for annexed load would *always* influence the annexation decision. BPA's Proposal should be rejected.

In the case of annexation, BPA's proposal indicates at page 69 that such service would be provided upon the earlier of either (i) written confirmation from both utilities that both agree to the annexation, or (ii) "final action by a court or state regulatory authority, or when a state agency clearly assigns the right to serve the annexed load." Again, BPA's Proposal indicates that "BPA's provision of transfer service should not influence the annexation outcome." This can only be accomplished if transfer service is limited to agreed-upon annexations. BPA should not offer to either arrange or pay for transfer service for annexed load, particularly in the absence of written confirmation from both utilities that both agree to the annexation.

3. Neither BPA's Low-Voltage Delivery Service nor Transfer Service Costs Should Be Rolled Into BPA's Main Grid Transmission Rates, and BPA Should Not Limit the Direct Assignment of Such Costs To Those Attributable To Facilities Below 34.5 kV

BPA has indicated that fundamental issues are (i) whether costs of transfer service (off-system deliveries) should be rolled into transmission or power rates and (ii) whether the costs of low-voltage delivery service should be rolled into BPA's main grid transmission rates.[34] Neither BPA's low-voltage delivery service nor transfer service costs should be rolled into BPA's main grid transmission rates, and BPA should not limit the direct assignment of such costs to those attributable to facilities below 34.5 kV.[35]

Under BPA's Proposal, Transfer Service costs for certain Wholesale Distribution Facilities below 34.5 kV may be directly assigned to the BPA customer receiving transfer service. Wholesale Distribution Facilities, in fact, include a number of facilities at or above 34.5 kV. The 34.5 kV level was established in a non-precedential settlement between BPA and BPA's transmission customers. BPA should reexamine this voltage level for this purpose and raise it.

The BPA main grid transmission rate should not include the costs of low-voltage delivery or metering facilities.[36] BPA for decades had a Customer Service Policy under which it would generally only install facilities for the delivery to generating preference utilities and investor-owned utilities of non-federal power at 230 kV or greater, but would install facilities for the delivery of federal power (typically to BPA full requirements customers) at much lower voltages.[37] Consequently, it would be inequitable for BPA to now collect the cost of these lower-voltage delivery facilities through the main grid segment (i.e., network) rates. BPA transmission customers such as generating preference utilities and investor-owned utilities pay BPA's main grid rates for the delivery of federal and non-federal power over BPA's main grid segment. Thus, these customers that bear the cost of their own lower-voltage facilities that they installed over the years under BPA's customer service policy should not also pay through BPA's main grid charge a portion of the cost of the lower-voltage facilities installed by BPA to deliver federal power to BPA's full requirement customers. This would be inequitable and in effect continue the results of the historically uneven treatment of BPA transmission customers. This would also violate the statutory requirement that the costs of the federal transmission system be equitably allocated among the federal and non-federal power utilizing such system.[38]

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[34] BPA's May 11, 2005, letter indicates that outstanding issues in the December 22, 2004 Administrator's Record of Decision, Proposed Contract with Transfer Service Customers Regarding the Initial Rate Treatment of Certain Transfer Service Costs and Other Issues Related to Transfer Service ("Transfer Service ROD") need to be resolved.

[35] BPA's costs for off-system deliveries cannot be allocated to BPA's transmission rates. *See* Northwest Power Act section 7(a)(2), 16 U.S.C. § 839e(a)(2). It would be particularly inappropriate to roll these costs, or BPA low voltage delivery service costs, into BPA's network transmission costs.

[36] BPA's Proposal at page 70 indicates that one of the areas of BPA cost in connection with transfer service is the following: "Scheduling and tracking non-Federal, Tier 2 power purchases and HWM compliance." These costs are clearly not attributable to BPA transmission and should be directly assigned or assigned to BPA's power rates or power customers.

[37] *E.g.,* 34.5 kV and above, up to (but not including) 230 kV facilities.

[38] *See* 16 U.S.C. § 839e(a)(2)(C).

4. Quality of Service

With respect to quality of service, BPA and transfer customers should commit to BPA's installation of real-time metering and telemetry facilities. Such facilities will promote the quality of service to BPA transfer customers.

F. BPA Resource Adequacy Standards

Much of the confusion regarding resource adequacy is due to uncertainty regarding BPA's load-serving obligations. As discussed above, a properly designed long-term BPA tiered rate methodology will clarify for BPA's customers the amount of power available from BPA at a rate based on the cost of the existing FBS. This will promote resource adequacy by facilitating resource planning and ensuring that those who place additional loads on BPA (rather than independently acquiring resources) pay BPA's full cost of serving those loads.

G. BPA Cost Control

BPA is faced with the challenge of managing the costs under its control so as to maximize the benefits of the existing FBS. BPA's rates are among the lowest wholesale rates in the region and the country. BPA has a solid base of low-cost hydroelectric resources in the existing FBS. This should allow BPA's lowest cost-based power rate to continue to be among the lowest wholesale rates in the region.

BPA should seek to provide service in the most cost-effective manner, consistent with its statutory obligations. In this regard, BPA and its customers should build on the experiences of the BPA Customer Collaborative and the Power Net Revenue Improvement Sounding Board. An effort should be made to look at what has worked in the past, enhance it, and formalize it as appropriate.

BPA cost control mechanisms should recognized that there are four general categories of BPA costs: (i) fish and wildlife costs, (ii) system augmentation costs, (iii) other internal costs, and (iv) other external costs. Instead of trying to develop a "one-size fits all" approach to cost control, it may be more effective to develop cost control approaches that are tailored to each of these categories.

- <u>Fish and wildlife costs</u>. Determining the appropriate level of BPA fish and wildlife costs requires identifying cost-effective actions based on clear, consistent goals founded in objective science. This can best be done in a broad forum that includes BPA customers and other stakeholders and that fosters a broad understanding of objective measures of the need for and effectiveness of various mitigation measures.

- <u>System augmentation costs</u>. BPA's power costs can increase dramatically if it is required to augment its system by acquiring power to serve increased loads. BPA can effectively control its augmentation costs with a long-term tiered rate methodology and allocation that ensures the rates for additional loads placed on BPA reflect the full cost of the power acquired by BPA to serve those loads.

- Other internal costs. These costs include costs of employees, overhead, transmission acquisition, conservation, renewable resources, federal debt service (primarily for Corps of Engineers and Bureau of Reclamation facilities), non-federal debt service (for Energy Northwest facilities), and risk mitigation. BPA has made and is continuing to make significant efforts optimize the level of and control its internal costs. In addition, BPA should explore employee incentives for effective cost control.

- Other external costs. These costs arise primarily through the operation and maintenance activities of three external organizations—the Corps of Engineers, the Bureau of Reclamation, and Energy Northwest. BPA's customers can play an increased role in helping BPA optimize and control the costs of these organizations paid by BPA. BPA and its customers should open up lines of well-defined communication to facilitate timely exchange of information and input into the spending decisions of these organizations. BPA and its customers should examine methods of enhancing their effectiveness in influencing the spending decisions of these organizations. For example, one such method would be to add BPA customer representation to the BPA/Corps/Bureau joint operating committees.

In addressing BPA cost control, it must be recognized that, to the extent BPA is exposed to the risk of power costs related to events that are outside of its control, BPA must collect revenues to address such costs. Historically, BPA's methods for collecting such revenues have included planned net revenues for risk ("PNRR") and cost recovery adjustment clauses ("CRACs"). BPA should consider such mechanisms for the future.

II. BPA MUST ADDRESS A NUMBER OF BASIC REP ISSUES

A. Basic REP Structure and Issues—ASC and Section 7(b)(2)

The utilities in the Pacific Northwest, including the PNW Investor-Owned Utilities, are entitled to exchange an amount of power equal to their full Pacific Northwest region residential and small farm loads. Section 5(c) of the Northwest Power Act, 16 U.S.C. § 839c(c)(1). This is the mechanism by which REP benefits are provided (in the absence of a settlement agreement). Under the REP exchange,[39] BPA sells power at BPA's PF Exchange Rate to the exchanging utility in an amount equal to the exchanging utility's residential and small farm load. The exchanging utility, in turn, sells an equivalent amount of power to BPA at the exchanging utility's ASC.[40]

In general, the net result of the REP is that the exchanging utility receives, for the benefit of its residential and small farm customers, the product of the load of such customers multiplied by the amount by which the exchanging utility's ASC exceeds the PF Exchange rate. The

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[39] These exchanges are accomplished under agreements commonly referred to as Residential Exchange Purchase and Sale Agreements ("RPSAs"). In 1981, each of the PNW Investor-Owned Utilities (and a number of BPA preference customers) implemented the REP by executing 20-year RPSAs. Although these agreements were scheduled to expire on June 30, 2001, the substantial majority of these agreements were replaced prior to their expiration with negotiated agreements that provided for payments of specified of REP benefits.

[40] Under certain circumstances, BPA may, in lieu of acquiring power from the exchanging utility under an RPSA, acquire power from another source (sometimes referred to as "in lieu power"). *See* section 5(c)(5) of the Northwest Power Act.

investor-owned utilities do not profit from the REP. The benefits of the REP flow directly to our residential and small farm customers and provide significant reductions in their electricity bills.

Details of the REP, including summaries of some of the disputes that have arisen under the REP, are set forth in Appendix A. Attached as Appendix B is a copy of a document entitled "Direct Testimony of the Pacific Northwest Investor-Owned Utilities" and labeled WP-07-E-JP6-01.[41]

BPA rate case issues—such as implementation of section 7(b)(2)—must be decided in a Northwest Power Act section 7(i) proceeding and are not subject to resolution in BPA's Regional Dialogue process. The arguments addressed in Appendices A and B are illustrative of the types of issues that the PNW Investor-Owned Utilities anticipate raising with respect to the determination of future REP benefit levels. The arguments addressed in Appendix B arising under the section 7(b)(2) rate step alone would, if successful and using the data described in Appendix B, produce annual REP benefits in excess of $520 million for the residential and small farm customers of the investor-owned utilities in FY 2013.

BPA's implementation of the 7(b)(2) step are addressed in two documents that were prepared by BPA in 1984 and that must be revised:

(i) BPA's "Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act" (the "Legal Interpretation"), 49 Fed. Reg. 23,998 (June 8, 1984).

(ii) BPA's Section 7(b)(2) Implementation Methodology, Administrator's Record of Decision (Aug. 1984) (the "Implementation Methodology").

The PNW Investor-Owned Utilities hereby request that BPA revise such documents consistent with the requirements of the Northwest Power Act and these comments.

The ASC Methodology must be revised and the PNW Investor-Owned Utilities hereby request that BPA institute a process to do so. Specifically, the PNW Investor-Owned Utilities request that BPA initiate a consultation process as provided in Section 5(c)(7) of the Northwest Power Act to change the ASC Methodology to be applied during the rate period beginning October 1, 2011. Among the elements of the ASC Methodology that should be revisited is the BPA Administrator's decision in 1984 to revise the initial ASC Methodology as negotiated with exchanging utilities in 1981 (the "1981 Methodology"). The new ASC Methodology (the "1984 Methodology") sharply reduced REP benefits received by the residential and small farm customers of the PNW Investor-Owned Utilities under RPSAs by removing the costs of income

[41] Consistent with the partial resolution of issues described in WP-07-E-BPA-31 at page A1 of Attachment A thereto, such document was neither proffered nor admitted into the record in the BPA WP-07 rate proceeding. Prior to such partial resolution of issues, the administrative law judge in the BPA WP-07 rate proceeding determined that some portions of such document either constituted statutory interpretation and legal argument or were irrelevant in the WP-07 rate proceeding. Nevertheless, BPA should recognize that arguments such as those contained in Appendix B must be addressed by BPA in the future.

taxes and equity capital from the ASC calculation. BPA's adoption of the 1984 Methodology was challenged by investor-owned utilities in *PacifiCorp v. FERC*, 795 F.2d 816 (9th Cir. 1986).

The Ninth Circuit upheld BPA's adoption of the 1984 Methodology modifying the 1981 Methodology to remove, among other costs, income taxes and return on equity from the ASC calculation as a "temporary" change to address the terminated nuclear plant costs issue. However, the Ninth Circuit did not sanction permanent implementation of the 1984 Average System Cost Methodology. Essentially, the court permitted BPA to exclude income taxes and equity as a means of preventing inclusion in the ASC of certain terminated plant costs. However, the costs of these unfinished nuclear plants will by 2011 have long been completely amortized or written off. Therefore, BPA's rationale for excluding income taxes and return on equity from the ASC methodology will no longer apply. Accordingly, the PNW Investor-Owned Utilities would seek to have BPA discontinue its long-standing use of its "temporary" change to the ASC Methodology.

B. In-Lieu Power

BPA must address the issue of what in-lieu power provisions to include in its RPSAs. These provisions should establish and clarify BPA's right to buy resources from the wholesale power markets, or otherwise, in lieu of buying an exchange resource from an exchanging utility under the REP. Such in-lieu power provisions should be workable, realistic and fair and should address issues such as notice needed to convert an exchange purchase into an REP sale with an in-lieu purchase; the term of such conversion; point(s) of delivery; and the source, amount, shape, and cost of the in-lieu power. Such in-lieu provisions in a RPSA should not be subject to unilateral amendment by BPA through policy revision.

C. Any Carryover of Deemer Account Balances is Flawed

1. Legal Arguments

Any carry-over of "deemer" balances to new long-term REP contracts would impose an inequitable and illegal result to the detriment of residential and small farm customers of investor-owned utilities. Deemer balances resulted from BPA's modification in 1984 of the ASC Methodology. This modification applied to REP contracts that were signed in 1981. This change in methodology caused a dramatic shift in the allocation of, and decrease in, the benefits under the 1981 REP contracts.

BPA's justification for changing the ASC Methodology in 1984, which applied to all exchanging utilities, was to prevent inclusion in the ASC by some utilities of terminated nuclear plant costs. Northwest investor-owned utilities challenged this change, and BPA's decision was upheld by the Ninth Circuit Court of Appeals, as a "temporary" change to address the terminated plant costs issue. *PacifiCorp v. FERC*, 795 F.2d 816, 823 (9th Cir. 1986) ("we do not sanction any permanent implementation of these exclusions"). However, the Court of Appeals did not sanction the permanent implementation of the revised ASC Methodology. Instead, the court permitted BPA to then exclude taxes and equity as a means of compensating for the inclusion in ASC of certain terminated plant costs.

The 1984 ASC Methodology change not only caused a significant reduction in the amount of benefits, but also had a significant impact on deemer accounts of some utilities. Although the utilities agreed in 1981 that deemer balances, if any, would be carried over to the next REP contract, it was not contemplated at the time that BPA could and would unilaterally make changes in ASC Methodology that would have the effect of permanently changing the value expected to be realized under the 1981 REP contracts. This clearly was not the intent of parties when they signed the contracts.

Additionally, the costs of those terminated plants in question will have been completely amortized or written off before new long term REP contracts are offered by BPA. Accordingly, and as indicated above, there is neither need nor justification for exclusion of income taxes and return on equity from future ASC calculations. Similarly, there is no financial need, nor legal justification, for use of historic deemer balances to diminish the benefits of residential and small farm customers under future REP contracts.

Deemer balances resulting from, what was in effect, BPA's unilateral amendment of the 1981 REP contracts, should not be carried over to new REP contracts. Although the exchanging utilities agreed in 1981 to the concept of deemer accounts resulting from changes in each exchanging utility's ASC, no one contemplated at that time that BPA could make a unilateral change in the ASC Methodology that would have the effect of reallocating the benefits of the REP across the region and near permanently depriving many residential and small customers of benefits under the Northwest Power Act. Accordingly, BPA has no equitable justification or express legal authority for preserving deemer balances in order to diminish the benefits for future residential and small farm customers of the federal hydroelectric system.

2. Practical Realities

The legal arguments expressed above notwithstanding, any BPA proposal to invoke the deemer accounts is also impractical—from the perspective of the need for political consensus . If BPA were to follow this track of invoking the deemer accounts in the fallback implementation of the REP, it would ensure that nearly a million electric customers in the region would immediately and near permanently lose their share of benefits of the FCRPS. This move is not consistent with the interests of regional fairness and equity or long term (or even the short term) sustainability of the Regional Dialogue process. The "regional civil war" that will necessarily follow any invocation of the deemer accounts will not only disrupt the implementation and ultimate success of the Regional Dialogue process, but will also prevent the alignment of interests necessary to preserve the benefits of the FCRPS for all electric consumers in the Pacific Northwest.

D. The Net Requirements of any Utility Should Be Decreased to the Extent It Both Purchases Power at Tier 1 Rates and Participates in the REP

BPA's Proposal indicates at page 20 that BPA expects that public power utilities would generally agree to settle their REP rights for nominal amounts, in the overall context of BPA's Proposal, and that such settlement is an essential element of BPA's Proposal. Although public power entities have a right to participate in the REP if they qualify, the legislative history of the Northwest Power Act indicates that this was considered unlikely:

> Although all utilities are permitted to enter into such [REP] sales, its benefits are likely to be limited to utilities that are not entitled to service as a preference customer.

H. Report 96-976, Part I (Commerce) at 60.

In addition, preference utility participation in the REP exposes BPA and its customers to costs that result if preference utilities curtail service from BPA in favor of then-cheaper resources that later turn out to be more expensive than BPA power. Historically, such curtailments of purchases from BPA by preference utilities have been significant:

> In 1994, market prices were dropping and conventional wisdom was that power market deregulation was likely to deliver consistently lower wholesale prices. By 1995, many BPA customers were clamoring to reduce their purchases from BPA so they could take advantage of lower prices offered by the burgeoning population of power marketers. The direct-service industries (DSIs) reduced their take from BPA by around 800 aMW in 1995, and public utilities followed in 1996 with over 1,000 aMW of load reductions. At this time, it was taken as a given by many of BPA's customers that they would no longer rely on BPA to meet all their requirements. The question was whether BPA could keep its costs low enough to avoid loss of so much load that a major "stranded cost" problem would result.[42]

Of course, the situation has now reversed, and preference utilities are "clamoring" for HWMs that will permit them to buy as much power as they can get from BPA at its Tier 1 rate. It would be ironic if the costs these entities incurred while they were away from BPA made them eligible to participate in the REP. Such utilities would benefit from the ability to purchase power at Tier 1 rates *and* participate in the REP based on higher cost resources acquired while they were away from BPA. *Cf.* Residential Exchange Program Settlement Agreement with Clark Public Utilities; Administrator's Record Of Decision, dated Feb. 10, 2006, which states as follows on page 6:

> Cowlitz County PUD (Cowlitz) expressed initial misgivings regarding Clark exchanging the costs of its River Road resource, which was developed in order to forego purchases from BPA and, in retrospect, has proven to be a costly decision.

In light of the foregoing, BPA should include—in any RPSA it enters into with any utility that has refused to settle its REP claims—a provision under which such utility agrees to dedicate to serving its firm load all, or a fraction of, the power purchased from BPA under its RPSA. To the extent the utility receives in-lieu power under its RPSA, all such power should be dedicated to serving the utility's firm load. To the extent the utility participates in the REP (but does not

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[42] BPA, "What Led to the Current BPA Financial Crisis? A BPA Report to the Region," at page 3 (Apr. 2003) <available at http://www.bpa.gov/corporate/docs/2003/Report_to_region.pdf>.

receive in-lieu power), the utility should dedicate a fraction of the amount of power it purchases under the RPSA. This dedication should apply in such circumstances even though the preference utility is selling to BPA an equal amount of power under the REP. The fraction of power purchased that is dedicated should be equal to the fraction of the utility's load served by purchases from BPA at BPA's Tier 1 rate. Such dedication of REP power to serve the utility's load will decrease the net requirements of the utility to the extent it is both purchasing power at Tier 1 rates and participating in the REP.

Such an approach is consistent with the 2006 Final Interpretation of Section 4(c)(10)(B) of the Northwest Power Act, which states as follows on page 3:

> Section 5(c) of the Northwest Power Act established the REP. Section 5(c)(1) of the Northwest Power Act provides that:
>
> > Whenever a Pacific Northwest electric utility offers to sell electric power to the Administrator at the average system cost of that utility's resources in each year, the Administrator shall acquire by purchase such power and shall offer, in exchange, to sell an equivalent amount of electric power to such utility for resale to that utility's residential users within the region.
>
> 16 U.S.C. § 839c(c)(1). Under the REP, the amount of the power purchased and sold equals a utility's residential and small farm load. *Id.* In BPA's ratemaking, BPA has always treated the REP as a purchase and sale of firm power. In implementing the REP, however, no actual power deliveries have taken place. For ease of administration, BPA has provided equivalent monetary benefits to the utility based on the difference between the utility's ASC and the applicable PF Exchange rate multiplied by the utility's residential load. Even under this approach, however, the Residential Purchase and Sale Agreements ("RPSA") implementing the REP have provided for actual power sales for "in lieu" transactions. 16 U.S.C. § 839c(c)(5). Section 5(c)(5) of the Northwest Power Act provides that, in lieu of purchasing any amount of electric power offered by a utility, the Administrator may acquire an equivalent amount of electric power from other sources to replace power sold to a utility as part of an exchange sale if the cost of the acquisition is less than the cost of purchasing the electric power offered by the utility. *Id.* In summary, section 5(c)(1) authorizes the Administrator to make firm power sales to exchanging utilities.

E. BPA Should Not Offer Long-Term Regional Dialogue Contracts Absent a Long-Term, Durable and Equitable REP Settlement

In the absence of a long-term, equitable and durable REP settlement, BPA should maintain long-term flexibility in its arrangements with its other power customers:

> When. . .issues affect the equity of how the benefits of the federal system flow to its customers, however, there may be a need to allow for more flexibility in the structure of such arrangements, or shorter contract lengths, or mechanisms that maintain equitable relationships between customers classes, to allow for changing conditions that could significantly affect equity calculations and/or perceptions.

What Led To The Current BPA Financial Crisis? BPA's Report to the Region (2003) at 26. http://www.bpa.gov/corporate/docs/2003/Report_to_region.pdf In short, BPA should not enter into long-term Regional Dialogue contracts with other customers without ensuring an equitable share of benefits for our customers over the same time period.

APPENDIX A

INVESTOR-OWNED UTILITY RESIDENTIAL EXCHANGE PROGRAM

I. The Residential Exchange Program ("REP")

In 1980, Congress enacted the Northwest Power Act,[43] which ended a looming regional civil war[44] being fought over access to the federal power system. Failure to extend an equitable share of the existing FBS to all of the region's residential consumers past FY 2011 would threaten to reopen old disputes and undermine the ability to maintain the value of the existing FBS for the region, thereby threatening to undermine the continued existence of BPA cost-based rates for the region and the regional preference.

For many years before the Act, BPA sold inexpensive federal power to both publicly-owned and investor-owned utilities.[45] All of those in the region whose tax dollars supported FCRPS benefited equally regardless of whether they lived in publicly-owned or investor-owned utility service territories. Then in the 1970s, due to increased population growth, BPA said it was no longer able to serve all the people in the region. BPA announced that firm power sales to investor-owned utilities would stop. This meant that the residential and small farm customers of investor-owned utilities would be denied access to federal power their taxes supported and those utilities would have to replace this federal power with new, much more expensive power.[46] One consequence of BPA's announced plan was the start of battles by publicly-owned utilities to take over areas served by investor-owned utilities—in order to get BPA "preference power."[47]

The potential gap in benefits from low-cost federal power in the region created "substantial political tension."[48] There were movements to start new utilities designed to be eligible to purchase preference power so that customers would get benefits from the existing low-cost federal power. For example, in 1977 the State of Oregon enacted a law creating the Domestic and Rural Power Authority ("DRPA") in order to get a share of federal preference power from BPA. DRPA planned to purchase and pass on the benefits of the low-cost federal power to Oregon residential and rural customers. DRPA was a major part of the impending battle over how to equitably share the federal power benefits. This fight set the stage for Congress to pass the Northwest Power Act in 1980. As Senator Henry M. Jackson of Washington said:

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[43] *Pub. Util. Comm'r of Or. v. Bonneville Power Admin.*, 767 F.2d 622, 625 (9th Cir. 1985); *see also* H.R. Rep. No. 96-976, pt. I, 96th Cong., 2d Sess., at 27 (1980) (hereafter "H.R. Rep. No. 96-976").

[44] H.R. Rep. No. 96-976 at 27.

[45] H.R. Rep. No. 96-976 at 24.

[46] H.R. Rep. No. 96-976 at 24-25.

[47] H.R. Rep. No. 96-976 at 25.

[48] Cong. Rec. – Senate 14,694 (1980).

> [W]e are on the verge of a decade-long legal and administrative battle over the allocation of the large but limited pool of low-cost Federal power. Unless the allocation issue is resolved promptly through legislation, no utility will be able to dependably plan its future needs and power supply.[49]

Senator Mark O. Hatfield of Oregon pointed out that there was

> . . . a vigorous revival of a movement to place the entire power systems in the Northwest under public ownership. In Oregon there were 12 elections to form local public people's utility districts on the ballot in November.[50]

The Congressional solution to this pending regional battle was to create REP benefits to allow residential and small farm electric utility customers in the region—regardless of whether they are served by publicly-owned or investor-owned utility power—to equitably share in the benefits of the federally funded hydroelectric projects. As Senator Jackson said:

> The [Northwest Power Act] make[s] it possible to immediately extend the economic benefits of low-cost federal power to consumers served by investor-owned utilities. . . .[51]

Congress decided to create wholesale rate parity to share the benefits of the region's federally funded hydroelectric system for all regional residential customers through the REP. The Ninth Circuit clearly and concisely set forth the Congressional intent:

> One of the goals of the Act is to ensure that residential consumers served by Northwest IOU's have wholesale rate parity with residential consumers served by publicly owned utilities and public cooperatives, BPA's preference customers. Parity is to be achieved through Residential Purchase and Sale Agreements between BPA and IOU's.[52]

Pub. Util. Comm'r of Or. v. Bonneville Power Admin., 767 F.2d 622, 624 (9th Cir. 1985).

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[49] Cong. Rec. – Senate 14,690-91 (1980).

[50] Cong. Rec. – Senate 14,694 (1980).

[51] Cong. Rec. – Senate 14,691 (1980).

[52] Similarly, the Washington Utilities and Transportation Commission testified in 1994 to Congress:

> Under the Pacific Northwest Electric Power Planning and Conservation Act (the Power Act), these customers are provided equal access to the benefits of the federal hydropower system through an "exchange" program.

BPA at Crossroads, Hearing Testimony Before the House Comm. on Natural Resources, Subcom. on Oversight and Investigations (Aug. 9, 1994) (statement of Judy Lamson, Policy Specialist, Washington Utilities and Transportation Commission).

A central purpose of the Northwest Power Act was to provide for regional unity and consensus; therefore, BPA's policies should not leave the 60 percent of the region's citizens served by the investor-owned utilities with an inequitable share of the benefits of the existing FBS. Failure to provide this 60 percent with an equitable share will lead to increased pressure to form publicly-owned utilities to take over areas served by investor-owned utilities. This pressure would at best frustrate the ability to preserve the value of the existing FBS for the region and ensure that its value is equitably distributed throughout the region. This pressure would undermine the ability to maintain the benefits of the existing FBS for the region—in the face of challenges to BPA cost-based rates for the region.[53]

The REP is a program designed to share a portion of the benefits of the federal power system with the 60 percent of residential customers in the Pacific Northwest who are served by the PNW Investor-Owned Utilities. BPA has stated that its goals include the following: "[s]pread the benefits of the [Federal Columbia River Power System] as broadly as possible, with special attention given to the residential and rural customers of the region. . . ." (Power Subscription Strategy, Administrator's Record of Decision (Dec. 1998) (the "Subscription ROD") at page 7.) BPA should ensure that the benefits of federal power are fairly divided among all citizens in the region as Congress intended. The six million citizens served by the region's investor-owned utilities[54] should not be shortchanged.

The utilities in the region, including the PNW Investor-Owned Utilities, are entitled to exchange an amount of power equal to their full Pacific Northwest region residential and small farm loads:

> Whenever a Pacific Northwest electric utility offers to sell electric power to the Administrator at the average system cost of that utility's resources in each year, the Administrator shall acquire by purchase such power and shall offer, in exchange, to sell an equivalent amount of electric power to such utility for resale to that utility's residential users within the region.

Section 5(c) of the Northwest Power Act, 16 U.S.C. § 839c(c)(1).

In the absence of a settlement agreement, REP benefits are provided using a Residential Purchase and Sale Agreement ("RPSA") between the exchanging utility and BPA. Under an RPSA, BPA sells power at BPA's PF Exchange Rate to the exchanging utility in an amount equal to the exchanging utility's residential and small farm load, and the exchanging utility sells an equivalent amount of power to BPA at the exchanging utility's average system cost of power

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[53] Early in 2005, the Administration proposed that BPA's rates be transitioned toward the wholesale market price of electricity. *See also, e.g.,* Reps. B. Franks & M. Meehan, *The Sensible Approach: Federal Power at Market Rates*, Pub. Util. Fort., Nov. 1, 1999, at 44-47.

[54] Of the ten and a half million people living in the BPA region, 60 percent are served by the PNW Investor-Owned Utilities—which means over six million people are served by the PNW Investor-Owned Utilities.

("ASC").[55] BPA develops and revises from time to time for use under RPSAs (i) the PF Exchange Rate and (ii) the methodology for determining ASCs[56] ("ASC Methodology").

Each of the PNW Investor-Owned Utilities (and a number of BPA preference customers) initially implemented the REP by executing 20-year RPSAs in 1981. Although these agreements were scheduled to expire on June 30, 2001, the substantial majority of these agreements were replaced prior to their expiration with negotiated agreements (in lieu of RPSAs) that provided for specified payments of REP benefits ("REP Settlement Agreements").

The extension of benefits of low-cost federal power to residential and small farm consumers served by investor-owned utilities in the region is a cornerstone of the Northwest Power Act. 16 U.S.C. § 839 *et seq.* As acknowledged in the Administrator's Final Record of Decision, WP-02-A-02 in the 2002 BPA power rate case, BPA has provided such benefits through the REP, or through settlements thereof, for over two decades. "Section 5(c) of the [Northwest Power Act] establishes a 'residential exchange' program designed to temper the inequity of the preference system mandated by the Bonneville Project Act of 1937, 16 U.S.C. §§ 832-832*l*." *Cal. Energy Res. Conservation & Dev. Comm'n v. Johnson,* 807 F.2d 1456, 1459 (9th Cir. 1985) ("*Johnson*").

The Subscription ROD recognized that distribution of the benefits of the FCRPS to residential and small farm consumers throughout the region is a core purpose for BPA. As stated in the REP Settlement ROD at 62 (quoting from BPA Power Subscription Strategy):

> "This strategy enables us to serve residential and small farm consumers directly by providing power for sale to the IOUs and other purchasers qualified under BPA statutes to serve those consumers so that the benefits of the Federal Columbia River Power System flow throughout the region whether those consumers are currently served by public or private power. This strategy reflects BPA's very roots."

(Emphasis in original.)

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[55] Because typically the sales of power back and forth between BPA and the exchanging utilities under RPSAs have been equal in amount, no net power has been scheduled under RPSAs; instead, BPA has made monetary benefit payments equal to the amount by which the ASC of each of the exchanging utilities exceeds BPA's PF Exchange Rate, multiplied by the utility's residential and small farm load.

[56] According to section 5(c)(7) of the Northwest Power Act, 16 U.S.C. § 839c(c)(7):

> The "average system cost" for electric power sold to the Administrator under this subsection shall be determined by the Administrator on the basis of a methodology developed for this purpose in consultation with the Council, the Administrator's customers, and appropriate State regulatory bodies in the region. Such methodology shall be subject to review and approval by the Federal Energy Regulatory Commission. . . .

II. Disputes Regarding REP Implementation

Historically, BPA's implementation of the REP has triggered numerous disputes before the Administrator, the Federal Energy Regulatory Commission ("FERC") and the courts. These disputes involved the key elements that affect the level of benefits under the REP: BPA's ASC[57] Methodology, utilities' ASCs, "in-lieu transactions," and BPA's PF Exchange Rate (including the section 7(b)(2) rate step).

Implementation of the REP under RPSAs necessarily requires BPA to make a number of projections and hypothetical assumptions using various methodologies. Over the more than 20-year period since BPA began implementing the REP, disputes regarding BPA's implementation have arisen and persisted, commencing with litigation over the initial, 1981 RPSAs:

> Under the Regional Act [Northwest Power Act], the contracts, once offered, were reviewable upon petition filed within 90 days. 16 U.S.C. § 839f(e)(5). The contracts generated considerable litigation. *See*, *e.g.*, *Aluminum Company*, 467 U.S. 380, 104 S.Ct. 2472, 81 L.Ed.2d 301; *Forelaws on Board v. Johnson*, 743 F.2d 677 (9th Cir. 1984); *Public Power Council v. Johnson*, 674 F.2d 791 (9th Cir. 1982).

Cal. Energy Res. Conservation & Dev. Comm'n v. Johnson, 783 F.2d 858, 859 (9th Cir. 1986) ("*CEC v. Johnson*") (footnote omitted). In *CEC v. Johnson*, for example, the California Energy Resources Conservation and Development Commission ("CEC") challenged the "in-lieu" provisions of the 1981 RPSAs and argued that they failed to conform with section 5(c)(5) of the Northwest Power Act, 16 U.S.C. § 839c(c)(5), which provides that under certain circumstances BPA may, in lieu of acquiring power from the exchanging utility under an RPSA, acquire power from another source.

This series of litigation was followed by other challenges of BPA's REP decisions, including *Central Electric Cooperative, Inc. v. Bonneville Power Administration*, 835 F.2d 199 (9th Cir. 1987); *CP Nat'l Corp. v. Bonneville Power Administration*, 928 F.2d 905 (9th Cir. 1991); and *Washington Utilities & Transportation Commission v. FERC*, 26 F.3d 935 (9th Cir. 1994).

In the absence of a settlement, the PNW Investor-Owned Utilities will continue to assert their arguments regarding elements of RPSAs, such as ASC Methodology, ASC determinations, in-lieu transactions, and PF Exchange Rate (including the section 7b(2) rate step).

III. The ASC Methodology Must Be Revised

PacifiCorp v. FERC, 795 F.2d 816 (9th Cir. 1986) ("*PacifiCorp*"), reviewed a decision in which the BPA Administrator in 1984 elected to revise the initial ASC Methodology that was negotiated with exchanging utilities in 1981 (the "1981 Methodology"). The new

[57] Average system cost ("ASC").

ASC Methodology (the "1984 Methodology") sharply reduced REP benefits received by the residential and small farm customers of the PNW Investor-Owned Utilities under RPSAs by removing the costs of income taxes and equity capital from the ASC calculation. As explained by the Court:

> The revised methodology had the effect of reducing the average system cost in two material ways. First, it eliminated income taxes from average system cost calculations, and second, it eliminated return on equity as a cost factor and substituted for it the embedded cost of long-term debt. The result is a substantial reduction in the amount of money which BPA pays to the IOUs under the exchange program.

795 F.2d at 819. This election to reduce REP benefits was challenged in a series of lawsuits by PNW Investor-Owned Utilities and by affected state regulatory agencies,[58] all leading to the decision in *PacifiCorp.*

In *PacifiCorp*, the Court upheld BPA's discretion as exercised in the 1984 Methodology to exclude certain costs from its ASC calculation, based on then-existing facts presented to the Court. Specifically, the Court relied on BPA's determination that certain terminated generation plant costs, which could not by statute be included in ASC, were being indirectly recovered through an increase in equity returns allowed to a utility. However, the Court's decision emphasized its reliance on these special facts and noted that it was not sanctioning a continuation of the exclusions once the need for them had passed:

> In upholding BPA's ASC determinations in this case, however, we do not sanction any permanent implementation of these exclusions. We uphold the exclusions in this instance because we conclude that we must defer to BPA's view that the statute authorizes such adjustments in ASC in response to BPA's experience with the program and the need to avoid abuses. The record in this case reflects that this is such a situation. The statute itself, however, neither commands nor proscribes these adjustments in ASC methodology.

795 F.2d at 823.

Faced with a requirement in 2000 to offer new RPSAs for execution prior to the end of June 2001, BPA needed to specify whether the ASC Methodology employed in the new, 2000 RPSAs as offered would continue the exclusions incorporated in the 1984 Methodology.

The PNW Investor-Owned Utilities had not waived their right to appeal any RPSA offer that continued the 1984 exclusions. Indeed, the key elements to be in the 2000 RPSAs were

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[58] *Pub. Util. Comm'r of Or. v. Bonneville Power Admin.*, 583 F. Supp. 752 (D. Or. 1984); *Pac. Power & Light Co. v. Bonneville Power Admin.*, 589 F. Supp. 539 (D. Or. 1984); *Pub. Util. Comm'r of Or. v. Bonneville Power Admin.*, 767 F.2d 622 (9th Cir. 1984).

vigorously disputed. For example, extensive comments on the proposed 2000 RPSAs in June of that year by Puget Sound Energy, Inc. and Avista Corporation to BPA demonstrated that the situation used to justify the 1984 exclusions would no longer apply and that the 1984 Methodology needed to be revised. These comments also objected to BPA's proposed in-lieu provision for the 2000 RPSAs, arguing that BPA's proposal was unreasonable, unworkable and contrary to the requirements of the Northwest Power Act.

With respect to ASC Methodology, the REP Settlement ROD[59] explained that BPA in its development of the 2000 RPSAs was faced with the challenge of the proposal to revert to the 1981 Methodology:

> Also, while BPA used the current ASC Methodology for its rate case forecasts, the methodology may be revised during the upcoming rate and contract period. . . . [R]evisions to the ASC Methodology are not merely speculative. As noted in BPA's RPSA ROD regarding proposed revision of the 1984 ASC Methodology, BPA concluded that BPA will begin regional discussions of whether the ASC Methodology should be revised during the currently proposed five-year rate and contract periods (FY 2002-2006).

The REP Settlement ROD continued by detailing the economic impacts of reverting to the 1981 Methodology:

> If, as suggested by the IOUs, BPA were to revert to the 1981 ASC Methodology, REP benefits for the upcoming rate and contract periods would be dramatically increased. Using a twenty-six percent escalation of ASCs to represent the 1981 ASC Methodology (the amount of average decrease in ASCs after adoption of the 1984 ASC Methodology) the average annual benefits for the five-year rate period would be approximately $323 million. Total REP benefits for the rate period would be $1.615 billion. Even assuming in-lieu transactions for fifty percent of the exchangeable loads, average annual benefits would be $161.5 million and total REP benefits for the five-year period would be $807.5 million. These figures still exceed the amounts of the proposed settlements.

Id.

The following Table 1 sets forth estimated ASCs of the PNW Investor-Owned Utilities.

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[59] Residential Exchange Program Settlement Agreements with Pacific Northwest Investor-Owned Utilities, Administrator's Record of Decision dated October 4, 2000 ("REP Settlement ROD") at 50.

TABLE 1

PNW Investor-Owned Utility	Estimated FY 2012 Residential and Small Farm Load (aMW)	Estimated FY 2012 ASC ($/MWh)
Avista Corporation	461	43.08
Idaho Power Company	773	41.98
NorthWestern Energy	97	47.00
PacifiCorp	1192	50.58
Portland General Electric Company	1195	54.54
Puget Sound Energy, Inc.	1301	54.98
PNW Investor-Owned Utilities	5010	50.58

Note: The above table is taken from the Pacific Northwest Investor-Owned Utility Comments on Long-Term BPA Regional Dialogue Policy Issues, dated June 13, 2005. This information has not been updated to reflect changes such as new resources and other cost pressures that affect ASCs. Indeed, in the last year, each of the region's investor-owned utilities has requested one or more rate increases—following an average increase in the residential rates of the region's investor-owned utilities from 2004 to 2005 of $2 per MWh, from about $66 to $68/MWh.

IV. The Section 7(b)(2) Rate Step Must Be Properly Performed

A. The 7(b)(2) Rate Step

An interim step in BPA's development of its power rates is the 7(b)(2)[60] rate step, which is described below and which, if it triggers, may result in adjustment of the level of REP benefits available to the residential and small farm customers of the region's investor-owned utilities. This step is a complex procedure, in which BPA compares two cost projections for a rate period and the ensuing four years: (1) a projection of costs of providing the general power requirements to BPA's preference and federal agency customers (with certain exclusions) with (2) a projection of the cost of power based upon five statutorily specified hypothetical assumptions. This hypothetical calculation may be generally described as follows:

(i) BPA Projects Program Case Costs. For the rate period plus the ensuing four years, BPA is to project amounts it would charge preference and federal agency customers for firm power for their general requirements (this amount is to be exclusive of amounts BPA would charge such customers under

[60] 16 U.S.C.A. § 839e(b)(2).

section 7(g) of the Northwest Power Act[61] for "the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events. . . .").

(ii) BPA Projects 7(b)(2) Case Costs. For the same period, BPA is to project the total hypothetical cost of power to meet the general requirements of its preference and federal agency customers if BPA assumes that:

(A) such customers' general requirements had included certain of BPA's direct service industrial customer loads during the period;

(B) such customers during the period were served with certain available BPA federal base system ("FBS") resources during the period;

(C) no residential exchange purchases or sales were made by BPA during the period;

(D) the least expensive resources owned or purchased by public bodies or cooperatives (not sold by such customers to BPA or committed to load) are available and used to meet the remaining general requirements of BPA's preference and federal agency customers during the period; and

(E) certain reduced preference agency financing costs and "reserve benefits as a result of the Administrator's actions under the [Northwest Power Act] were not achieved" during the period.

16 U.S.C. § 839e(b)(2).

If the Program Case Costs projection described in item (i) above, as reduced by such 7(g) costs, exceeds the 7(b)(2) Case Costs projection described in item (ii) above, the 7(b)(2) rate step is said to "trigger" and the amount of such excess, if any, is referred to as the "trigger amount." Triggering of the 7(b)(2) rate step may, but does not necessarily, cause the PF Exchange Rate to exceed the PF Rate.

B. BPA Reserve Benefits Are Not Limited to DSI Sales

1. BPA reserve benefits reduce the trigger amount.

BPA "reserve benefits" reduce any 7(b)(2) trigger amount because, as discussed above, one of the assumptions in making the cost projection for the 7(b)(2) Case is that reserve benefits as a result of the Administrator's actions under the Northwest Power Act[62] were not achieved.[63]

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[61] 16 U.S.C. § 839e(g)

[62] Such projected reserve benefits are typically referred to as the "value of reserves" or "reserve benefits."

2. BPA reserve benefits result from BPA's rights to interrupt power sales in order to benefit its regional firm power customers.

The Northwest Power Act defines "reserves" as follows:

> "Reserves" means the electric power needed to avert particular planning or operating shortages for the benefit of firm power customers of the Administrator and available to the Administrator (A) from resources or (B) from rights to interrupt, curtail, or otherwise withdraw, as provided by specific contract provisions, portions of the electric power supplied to customers.

16 U.S.C. § 839a(17). The "planning or operating shortages" that BPA might experience could be caused for example by low or critical streamflow conditions, delayed completion or unexpectedly poor performance of regional generating resources or conservation measures, and the unanticipated growth of regional firm loads.[64] This was true in 1980 and remains true today.

Reserve benefits are the benefits BPA has as a result of rights to interrupt power sales in order to benefit firm power sales to BPA's utility customers in the region for various reasons—such as unanticipated growth of regional firm loads, delayed completion or poor performance of regional generating resources and low streamflows.[65]

3. BPA reserve benefits are not limited to benefits from rights to interrupt DSI power sales.

The Northwest Power Act definition of "reserves" does not limit reserves to those from any particular source, DSIs or otherwise, and reserve benefits as a result of the Administrator's actions under the Northwest Power Act are not limited to the benefits of reserves from any particular source. Indeed, section 5(d)(1)(A) of the Northwest Power Act states as follows:

> The Administrator is authorized to sell in accordance with this subsection electric power to existing direct service industrial

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[63] Making this assumption increases the cost projection for the 7(b)(2) Case, which decreases the trigger amount (the amount if any by which the Program Case projection exclusive of specified section 7(g) costs exceeds the 7(b)(2) Case projection).

[64] The Senate Committee on Energy and Natural Resources Report states as follows regarding the purpose and role of reserves under the Northwest Power Act:

> to protect firm loads for any reason, including low or critical streamflow conditions, and . . . to protect firm loads against the delayed completition [sic] or unexpectedly poor performance of regional generating resources or conservation measures, and against the unanticipated growth of regional firm loads. . . .

U.S. Senate Committee on Energy and Natural Resources Report No. 96-272 at 28.

[65] BPA's wholesale market surplus sales are, in effect, analogous to sales to interruptible customers that can be curtailed to benefit BPA's firm power loads.

> customers. Such sales provide a *portion* of the Administrator's reserves for firm power loads within the region.

16 U.S.C. § 839c(d)(1)(A) (emphasis added). In other words, BPA's rights to interrupt power sales to the DSIs to benefit firm power sales to BPA's utility customers in the region are not the exclusive source of BPA's reserves under the Northwest Power Act.

4. BPA surplus sales in the wholesale power market meet the Northwest Power Act definition of "reserves."

BPA surplus sales in the wholesale market are made under the Northwest Power Act[66] and constitute reserves (and provide reserve benefits) under the Northwest Power Act. Reserves include BPA's rights to interrupt, curtail or otherwise withdraw sales of surplus power when necessary. BPA sells surplus energy in the real-time, day-ahead, balance-of-month and forward electricity markets, controlling the duration of those sales so that BPA can withdraw power from the wholesale market when needed for its regional firm power customers. BPA's wholesale market surplus sales thus benefit, and avoid service and cost risks to, BPA's utility firm power loads in the region.

Thus, BPA's "secondary market" or "surplus" power sales in the wholesale power market meet the definition of "reserves" under the Northwest Power Act and fulfill the purposes contemplated for BPA reserves under the Northwest Power Act. These BPA "secondary market" or "surplus" power sales are substantial.

BPA has not lost reserve benefits because of the diminishment of DSI load. In fact, BPA has reserve benefits from its surplus power sales in the wholesale power market that are superior in several respects to those it previously received from its sales to DSIs. For example, the DSI reserves provided recall or interruption rights only for specified portions of the power sales to the DSIs and only for specified purposes and durations. By contrast, BPA has much more flexibility in its wholesale market surplus sales to establish withdrawal or recall rights through limitation of the term of the sale and otherwise.

5. BPA, in fact, uses its wholesale market surplus sales as reserves.

BPA exercises recall rights under contracts and does not renew surplus sales in the wholesale power market when the power is needed to serve BPA's firm loads. For example:

> With the Northwest facing power shortages as early as this winter, BPA is giving notice to its California customers that long-term

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[66] BPA makes surplus sales in the wholesale power market pursuant to section 5(f) of the Northwest Power Act:

> [BPA] is authorized to sell, or otherwise dispose of, electric power, including power acquired pursuant to [the Northwest Power Act] and other Acts, that is surplus to [BPA's] obligations . . . .

16 U.S.C. § 839c(f).

> contracts for surplus and excess federal power sales will not be renewed. Where contracts have recall or conversion rights, BPA is exercising those rights. BPA sold several hundred megawatts of power to California when the Northwest had surplus and excess power.
>
> By law, BPA is directed to sell outside the Northwest only power that is surplus to the region's needs. Buyers have different rights under each contract. Where contract terms allow, BPA can convert energy sales into capacity exchanges or give notice of termination. In contracts that contain no recall or conversion provisions, BPA is notifying California buyers that contracts will not be renewed.

"BPA Recalls California Contracts," BPA Journal (Oct. 2000) at page 3. Similarly, BPA has halted surplus sales when needed to meet its regional firm loads:

> When the cold snap hit, BPA reduced its surplus sales to meet required loads in the Northwest. BPA structures surplus sales to gain revenue while retaining the ability to recall the power when it is needed. Revenue gained from selling surplus power is used to offset power purchases when Northwest loads exceed BPA capacity.

"Power Demand Soars as Temperatures Plummet," BPA Press Release (Feb. 2, 1996) at page 1.

In sum, BPA makes extensive surplus power sales at market prices in the wholesale power market that provide substantial reserve benefits to BPA. These reserve benefits will eliminate or greatly reduce any 7(b)(2) trigger amount that might otherwise occur. Thus, even in the absence of DSI sales, BPA has reserve benefits that reduce or eliminate the 7(b)(2) trigger amount.

C. The Absence of DSI Sales Does Not Preclude REP Benefits

Prior to July 1, 1985, DSI rates ensured BPA's recovery of amounts to provide REP benefits. Section 7(c)(1)(a) of the Northwest Power Act provides that DSI rates shall be established

> for the period prior to July 1, 1985, at a level which the Administrator estimates will be sufficient to cover the costs of resources the Administrator determines are recovered to serve such customers' loads and the net costs incurred by the Administrator pursuant to [the REP] . . ., to the extent that such costs are not recovered by rates applicable to other customers . . . .

Consistent with this, the legislative history of the Northwest Power Act states that the "cost of the exchange during the first five years is charged to the rates applicable to DSI's under section 7(c)(1)(A)." H. Report 96-976, Part I (Commerce) at 61.

After July 1, 1985, section 7(c)(1)(A) no longer applies, and DSI rates do not alone ensure BPA's recovery of amounts to provide REP benefits.[67] In short, after that date, DSIs do not alone ensure BPA's recovery of amounts to provide REP benefits, and the absence of DSI sales does not preclude REP benefits.

D. Section 7(b)(2) Is Not An Absolute Cap on the PF Preference Rate

Section 7(b)(2) of the Northwest Power Act is an interim rate step in the development of BPA's power rates, not a rate cap that creates an absolute limit on the PF Preference rate.

1. Section 7(a) of the Northwest Power Act requires BPA to establish rates that recover its costs.

Section 7(a) of the Northwest Power Act provides that BPA must establish rates that will recover its costs. 16 U.S.C. § 839e(a). If BPA's proposed rates are not set to recover BPA's total costs, such proposed rates cannot be approved by the Federal Energy Regulatory Commission ("FERC") and implemented. 16 U.S.C. § 839e(a)(2).

The Northwest Power Act contains a number of other rate directives. As discussed below, these other rate directives--such as the 7(b)(2) rate step--must be implemented in a manner that avoids conflict with the cost-recovery mandate of section 7(a) of the Northwest Power Act.[68]

2. Section 7(b)(2) is an interim rate step.

BPA concluded in 1984, when it was first implementing section 7(b)(2), that this section does not establish a rate cap that is an absolute limit on the PF Preference rate but rather is an interim ratemaking step that BPA implements consistent with other statutory provisions and BPA's ratemaking objectives. BPA's conclusion is reflected in its 1984 Legal Interpretation[69] and Implementation Methodology.[70]

The Legal Interpretation recognized that (i) section 7(a) requires that BPA's rates must be "sufficient to collect its costs" and (ii) BPA's rates cannot be confirmed and approved by FERC (and therefore cannot be placed into effect) if such rates are not established in accordance with section 7(a). 16 U.S.C. § 839e(a)(2). The Legal Interpretation concluded as follows:

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[67] As discussed below, section 7(b)(2) applies after that date; however, section 7(b)(2) is an interim rate step that may, under some circumstances, reduce the PF Preference rate but does not specifically require the assignment of REP costs *per se* to DSIs or any other BPA customer class.

[68] Section 7(g) of the Northwest Power Act provides for the allocation of costs and benefits not otherwise governed by statute in an equitable manner and as appropriate to any or all of the rates for power sales of the Administrator in order to ensure that BPA can meet the requirements of section 7(a) to collect sufficient revenues to recover all of BPA's costs and repay the federal Treasury. Section 7(g) was drafted to be totally inclusive, precisely because of the overriding imperative that the federal Treasury be repaid in full.

[69] "Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act", 49 Fed. Reg. 23,998 (June 8, 1984).

[70] Section 7(b)(2) Implementation Methodology, Administrator's Record of Decision (Aug. 1984).

> BPA will interpret section 7(b)(2) so that implementation of section 7(b)(2), and any subsequent reallocation pursuant to Section 7(b)(3), will not conflict with the requirements of section 7(a).

Legal Interpretation, 49 Fed. Reg. at 24,001. Similarly, the Implementation Methodology concluded that the section 7(b)(2) rate step is only a step in BPA's ratemaking process and must not be implemented in a manner that conflicts with BPA's other statutory provisions and BPA's ratemaking objectives.

Thus, the section 7(b)(2) rate step is an interim step in BPA's determination of power rates. Accordingly, as an interim rate step that is followed by subsequent steps, section 7(b)(2) cannot be read in isolation; rather, any interpretation of it must reflect the fact that BPA's rates must recover its costs.

3. Section 7(b)(2) incorporates hypothetical cost projections.

As discussed above, section 7(b)(2) is based on hypothetical assumptions and projected amounts that extend beyond the rate period. BPA's rates cannot be capped based on such hypothetical projections if BPA is to be assured of meeting its overriding statutory directive to collect its actual costs and repay the federal Treasury.[71]

E. Section 7(b)(2) Does Not Require That REP Benefits Be Recovered Only Through DSI Rates

Prior to July 1, 1985 DSI rates, in fact, ensured BPA's recovery of amounts to provide REP benefits. Section 7(c)(1)(a) of the Northwest Power Act provides that DSI rates shall be established

> for the period prior to July 1, 1985, at a level which the Administrator estimates will be sufficient to cover the costs of resources the Administrator determines are recovered to serve such customers' loads and the net costs incurred by the Administrator pursuant to [the REP] . . ., to the extent that such costs are not recovered by rates applicable to other customers . . . .

Consistent with this, the legislative history of the Northwest Power Act states that the "cost of the exchange during the first five years is charged to the rates applicable to DSI's under section 7(c)(1)(A)." H. Report 96-976, Part I (Commerce) at 61.

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[71] Treating section 7(b)(2) as an absolute limit on the PF Preference rate would render BPA unable to administer not only the REP but also virtually all of BPA's ongoing programs. For example, BPA projects fish and wildlife costs as part of the 7(b)(2) Case. Such projection is but one of a myriad of cost projections in the 7(b)(2) Case, all of which may vary from BPA's actual costs. BPA must pay its actual costs, not its rate case forecasted costs. BPA's cost projections do not, and cannot, constitute a *de facto* spending limit on BPA's actual fish and wildlife costs. Similarly, BPA projects REP benefits as part of the 7(b)(2) Case. In doing so, BPA estimates REP loads, ASCs and other REP elements. However, such projections are estimates that do not and cannot constitute a *de facto* limit on BPA's REP benefits.

After July 1, 1985, section 7(c)(1)(A) no longer applies, and DSI rates do not alone ensure BPA's recovery of amounts to provide REP benefits.[72] In short, after that date, DSIs do not alone ensure BPA's recovery of amounts to provide REP benefits, and the absence of DSI sales does not preclude REP benefits.

The 7(b)(2) rate step specifically requires that "the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events. . . .charged under section 7(g) of the Northwest Power Act be subtracted from the Program Case costs before those costs are compared with the 7(b)(2) Case. If the Program Case Costs projection described in item (i) above, as reduced by such 7(g) costs, exceeds the 7(b)(2) Case Costs projection described in item (ii) above, the 7(b)(2) rate step is said to "trigger." Triggering of the rate step may, but does not necessarily, cause the PF Exchange Rate to exceed the PF Rate.

As noted in the REP Settlement ROD, the investor-owned utilities in BPA's WP-02 rate case

> contested a number of assumptions BPA used in developing the proposed PF Exchange rate. If the IOUs successfully challenge that rate, the rate could be reduced and REP benefits increased. The possible impact of these changes is significant and must be considered in developing a settlement proposal.

REP Settlement ROD at 51. In that rate case to determine BPA's power rates for the period commencing October 1, 2001, the PNW Investor-Owned Utilities were vigorously contesting aggressive determinations by BPA that had the effect of increasing the PF Exchange Rate. These issues as well as other 7(b)(2) rate step issues are not ripe for resolution in this BPA proceeding.

V. The Use of REP Settlement Agreements Is a Long-Established, Reasonable BPA Practice

REP Settlement Agreements have been offered and entered into to eliminate the uncertainty as to the level of REP payments, to ease the administrative cost of the REP program and to resolve disputes over the appropriate levels of REP benefits.

Under the current REP settlement agreements, the PNW Investor-Owned Utilities will receive, for the benefit of their residential and small farm customers, between $100 million and $300 million per year in monetary payments for the period of FY 2007-2011. These payments are calculated based on the amount by which the market price exceeds the PF rate, multiplied by 2,200 aMW. Under the settlements for the period FY 2002-2011, the allocation of payments to each PNW Investor-Owned Utility for its residential and small farm customers was made consistent with the recommendations of the Pacific Northwest State Utility Commissions. In addition, under the terms of the current REP settlement agreements, the PNW Investor-Owned Utilities will receive no firm power during the FY 2007-2011 period.

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[72] As discussed below, section 7(b)(2) applies after that date; however, section 7(b)(2) is an interim rate step that may, under some circumstances, reduce the PF Preference rate but does not specifically require the assignment of REP costs *per se* to DSIs or any other BPA customer class.

With respect to determination of the PF Exchange Rate, the REP Settlement ROD explained contested issues regarding development of that rate that could have a significant impact:

> Another variable concerns BPA's PF Exchange rate. REP benefits are determined by the difference between a utility's ASC and the PF Exchange rate. If the PF Exchange rate is reduced, exchanging utilities receive greater benefits. As noted in BPA's 2002 rate case, the IOUs contested a number of assumptions BPA used in developing the proposed PF Exchange rate. If the IOUs successfully challenge that rate, the rate could be reduced and REP benefits increased. The possible impact of these changes is significant and must be considered in developing a settlement proposal. In BPA's 2002 rate case, the IOUs filed testimony stating the different issues that they contested regarding the PF Exchange rate. The IOUs also stated the effect on REP benefits that would result if the rate were developed as they suggest.

REP Settlement ROD at 51 (citations omitted). The REP Settlement ROD quantified economic impacts of contested revisions to the PF Exchange Rate in the WP-02 rate proceeding:

> The IOUs noted that proposed corrections to the DSI floor rate would increase REP benefits by $3,033,000 per year. The IOUs noted that a correction of the IP/PF link by including revenue taxes in the margin would increase REP benefits by $8,322,000 per year. The IOUs noted that including the costs of Planned Net Revenues for Risk as uncontrollable events in the section 7(b)(2) rate test would increase REP benefits by $54,555,000 per year. The IOUs noted that including conservation in the FBS would increase REP benefits by $111,950,000 per year. The IOUs noted in their initial brief that failure to treat terminated plants as uncontrollable events would increase REP benefits by $243 million per year. The IOUs noted that, in summary, REP benefits would have increased to $280 million per year if BPA's rates were developed as they proposed. This amount of REP benefits is *substantially* greater than the proposed amount of settlement benefits. Even assuming that Vanalco and the DSIs were correct in placing the total five-year Subscription settlement benefits at $736.6 million, this is far, far less than the forecasted $1.4 billion of REP benefits calculated by the IOUs.

Id. at 51-52 (citations omitted).[73]

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[73] Further, the REP Settlement ROD discussed uncertainty or risks regarding ASC forecasts.

In the WP-02 proceeding alone, the PNW Investor-Owned Utilities had residential exchange purchase and sale claims—for benefits for their residential and small farm customers—of at least $1.225 billion ($245 million per year times five years):

> We [the PNW Investor-Owned Utilities] believe that the Residential Exchange benefits over the five-year rate period should be at least $280,000,000 per year, which is $245,000,000 per year higher than BPA has proposed.

Direct Testimony of the Northwest Investor-Owned Utilities, WP-02-EAC/GE/IP/MP/PL/PS-02, at 2 (Nov. 2, 1994).

Since the inception of the REP, BPA and utilities have negotiated and entered into numerous agreements settling REP rights:

> Beginning in 1981, BPA and exchanging utilities executed RPSAs [residential exchange purchase and sale agreements] for 20-year terms. Between 1981 and today, all of these RPSAs have been settled except for one. . . . This extremely large number of Residential Exchange settlements reflects the nature and benefits of such settlements. *Parties are able to avoid the contentiousness of the myriad Residential Exchange issues,* thereby saving significant administrative and legal expenses. *Parties receive known benefits instead of guessing future benefits due to changes in the ASC Methodology, the determination of ASC reports, and the development of wholesale power rates. . . .*

Prefiled BPA Direct Testimony in BPA's WP-02 Rate Proceeding, WP-02-E-BPA-19, at 10-11 (emphasis added).

Indeed, prior to BPA's decision to offer the current REP settlement agreements, BPA had entered into some 30 prior REP settlement agreements dating back to at least 1988. Most of the counterparties to these prior REP settlement agreements were not the PNW Investor-Owned Utilities but were in fact BPA preference utility customers.[74]

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[74] Prior to entering into the current REP settlement agreements, BPA had previously offered and entered into REP settlement agreements with not only PacifiCorp, PSE, and PGE, but also the following BPA preference ustomers: PUD No. 1 of Snohomish County, WA; PUD No. 1 of Clallam County, WA; Glacier Electric Cooperative; PUD No. 1 of Klickitat County, WA; Prairie Power Cooperative, Inc.; Vigilante Electric Power Cooperative, Inc.; Flathead Electric Cooperative, Inc.; PUD No. 1 of Grays Harbor County, WA; Orcas Power & Light Co.; Salmon River Electric Cooperative, Inc.; Blachly-Lane Electric Cooperative Association; Central Electric Cooperative, Inc.; Consumers Power, Inc.; Coos-Curry Electric Cooperative, Inc.; Douglas Electric Cooperative, Inc.; Lost River Electric Cooperative, Inc.; Oregon Trail Electric Cooperative; Raft River Electric Cooperative, Inc.; Umatilla Electric Cooperative Association; PUD of Clark County; City of Idaho Falls; Oregon Trail Electric Consumers Cooperative; Lewis County PUD; Inland Power & Light Company; the Pacific Northwest Generating Cooperative; Fall River Rural Electric Cooperative; Lower Valley Power & Light, Inc.; Benton Rural Electric Association; Clearwater Power Company; and Harney Electric Cooperative, Inc.

These previous REP settlement agreements included a 1988 agreement with Public Utility District No. 1 of Snohomish County, Washington ("Snohomish"). Certain provisions of the Snohomish REP settlement agreement are worth quoting, as they describe the settlement and the reasons for it:

> Attributes unique to public utilities and their ratemaking processes have very much complicated BPA's administration of, and public utilities' participation in, the Residential Exchange Program through the existing Average System Cost (ASC) methodology. This has also resulted in disagreements between the District and BPA regarding the interpretation and implementation of the ASC methodology, which has on occasion resulted in litigation. It is in the interest of the District and BPA to minimize the burdens associated with the regulatory review of the District's periodic filings under the ASC methodology, to eliminate the administrative disruption caused by this subsidy program, and remove this area of potential controversy.
>
> To achieve these mutually beneficial goals, the District agrees to terminate its RPSA effective December 31, 1987. In consideration for this action by the District regarding the RPSA, BPA agrees to pay the District the sum of forty three million three hundred thousand dollars ($43,300,000.00) with interest as applicable, all as set forth in paragraphs 7 and 8 of this Agreement.

The REP Settlement ROD (at page 57) described prior REP settlement agreements:

> Notably, BPA has previously entered into some thirty Residential Exchange Termination Agreements with exchanging utilities during the past 20 years. None of those settlements contained provisions for updating costs or periodically reviewing eligibility. Instead, BPA and the utility negotiated a reasonable amount of settlement benefits to terminate the utility's participation in the REP for a significant period. Indeed, a notable number of these settlements have effective terms of 12 to 15 years, which are *longer* than the terms of the proposed Settlement Agreements. Nevertheless, BPA did not require revisiting the settlements during their respective terms.

Thus, BPA customers, preference and PNW Investor-Owned Utilities alike have consistently taken advantage of the benefits of settling REP rights by entering into REP settlement agreements. These agreements have had extended terms. They have consistently, during those terms, extinguished RPSAs and REP rights in exchange for payments not expressly tied to the elements of the REP, such as ASC and PF Exchange Rate.[75]

VI. A COMPARISON OF RESIDENTIAL RETAIL RATES IS NOT AN APPROPRIATE METHOD FOR ASSESSING THE ALLOCATION OF FCRPS BENEFITS

The U.S. Court of Appeals for the Ninth Circuit recognized the Congressional intent to provide *wholesale* rate parity in the region through the REP:

> One of the goals of the Act is to ensure that residential consumers served by Northwest IOU's have *wholesale* rate parity with residential consumers served by publicly owned utilities and public cooperatives, BPA's preference customers. Parity is to be achieved through Residential Purchase and Sale Agreements between BPA and IOU's.

Pub. Util. Comm'r of Or. v. Bonneville Power Admin., 767 F.2d 622, 624 (9th Cir. 1985) (emphasis added). Indeed, the House Report stated that the REP should provide *wholesale* rate parity, not *retail* rate parity:

> The [REP] is not likely to result in parity in the retail rates being paid by consumers of preference customers and consumers of investor-owned utilities, but it *should equalize the wholesale costs* of the electric power with a resulting benefit [to] the investor-owned utilities' customers.

H. Report 96-976, Part I (Commerce) at 60 (emphasis added).

A comparison of residential retail rates is not an appropriate method for assessing the allocation of FCRPS benefits. Retail rates reflect not only the costs and benefits of the FCRPS, but also other power costs, as well as transmission, distribution and customer service costs, all of which vary from utility to utility. Further, residential retail rates are determined by the individual decisions of each utility regarding how it should best allocate these costs among its various customer classes. Because residential retail rates reflect allocated costs from all of these cost categories, residential retail rates do not provide a useful basis for assessing the allocation of FCRPS benefits among BPA's utility customers.

The allocation of FCRPS benefits among BPA's utility customers is, however, reflected in (i) the PF Preference rate for sales to BPA's preference customers and (ii) the REP benefits received by BPA's customers. The allocation of FCRPS benefits among BPA's utility customers can be assessed by comparing (i) the effective PF Preference rate to (ii) the effective ASCs for

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[75] Indeed, any suggestion that settlements by BPA cannot include power transactions with payments based on formulae using variables other than ASC and PF Exchange Rate is erroneous. *Util. Reform Project*, 869 F.2d at 441 (upholding BPA settlement that included a power transaction with payments based on a formula using "the average costs of the surrogate plants").

power delivered to residential customers of utilities receiving REP benefits (*i.e.*, average ASC less average REP benefits).

The figure below compares[76]

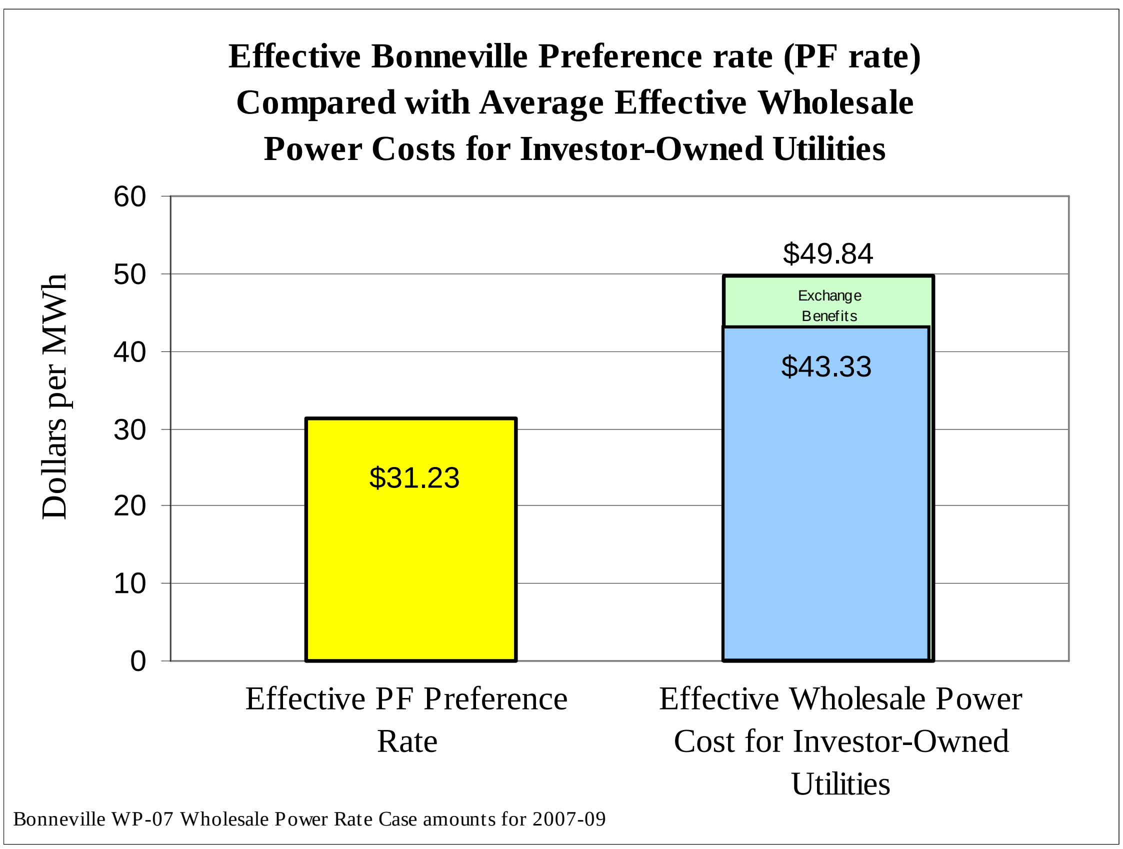
(i) BPA's average effective PF Preference rate, assumed to be $31.23/MWh ($27.33/MWh for the PF Preference rate plus $3.90/MWh for BPA transmission);

(ii) BPA's projected average investor-owned utility ASC, assumed to be $49.84/MWh; and

(iii) the average *effective* investor-owned utility ASC, $43.33/MWh, for power delivered to residential customers (*i.e.*, average investor-owned utility ASC less average investor-owned utility REP benefits).

The figure below shows, in this analysis, that the effective PF Preference rate is substantially lower than the average investor-owned utility ASC, even when the average investor-owned utility ASC is reduced by average investor-owned utility REP benefits:

FIGURE 1



[76] This analysis assumes that there will be a nominal level of REP benefits for preference utilities.

Even though a comparison of residential retail rates is not an appropriate method for assessing the allocation of FCRPS benefits, it might be noted that some have erroneously argued that the retail rates of investor-owned utilities are disproportionately low due to REP benefits. Based on the most recent data generally available, the average residential rates in the region for investor-owned utilities and for public power are virtually identical. The 2004 retail rate data from the U.S. Department of Energy, Energy Information Agency ("EIA") indicates that the average residential rate for BPA preference customers is $68.39/MWh. The 2005 retail rate data from the Edison Electric Institute indicates that the average residential rate for the region's investor-owned utilities is $68.09/MWh. This data does not reflect the impact of subsequent retail rate changes, such as subsequent reductions in public power residential rates due to reductions in the PF rate.

In the last year, each of the region's investor-owned utilities has requested one or more rate increases. And this follows an average increase in the residential rates of the region's investor-owned utilities from 2004 to 2005 of $2 per MWh, from about $66 to $68/MWh. By contrast, public power's average customer bills have been typically held constant or, in many cases, have decreased. For example, Eugene Water & Electric Board has rates that have remained relatively stable since the fall of 2004. Benton PUD recently announced a 4 percent rate decrease, the third consecutive rate decrease for residential customers since April 2004. Further, Seattle City Light recently announced a 2.2 percent rate decrease for its residential customers.

The following figure depicts the average residential retail rates described above, together with the average PF Preference rate and effective ASC for investor-owned utility residential and small farm customers from Figure 4.

FIGURE 2

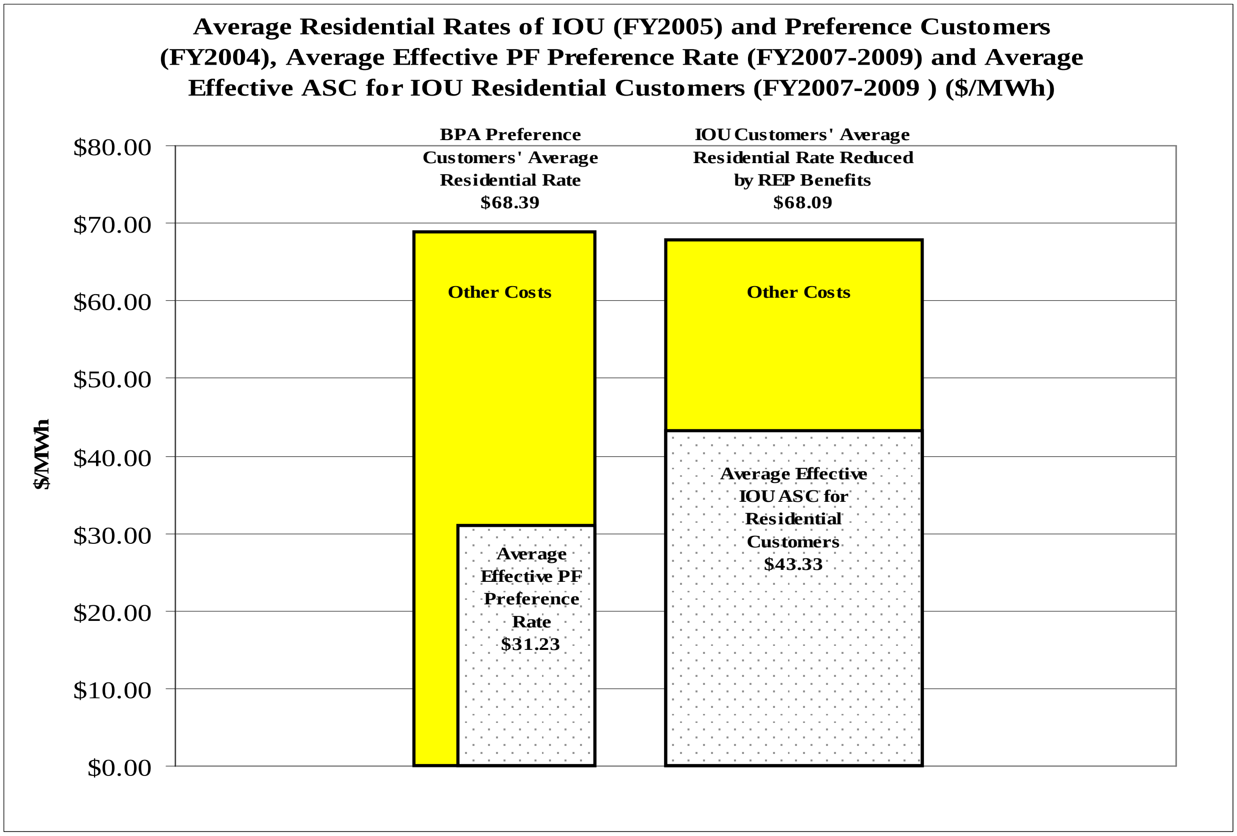


Figure 2 again demonstrates that the average residential rates of the investor-owned utilities and BPA preference customers were roughly equal, even though the proposed PF Preference rate is substantially lower than the projected average effective investor-owned utilities ASC. By the widths of the bars, Figure 2 also roughly represents the relative sizes of (i) the residential loads of the investor-owned utilities (57 percent) and BPA preference customers (43 percent) and (ii) the relative sizes of residential loads of BPA preference customers served by purchases at the PF Preference rate (75 percent) and served by other resources (25 percent).

APPENDIX B

ILLUSTRATIVE EXAMPLES OF 7(B)(2) ISSUES TO BE ADDRESSED IN FUTURE BPA RATE CASES

(Consistent with the partial resolution of issues described in WP-07-E-BPA-31 at page A1 of Attachment A thereto, the "Direct Testimony of the Pacific Northwest Investor-Owned Utilities" a copy of which is attached as Appendix B, was neither proffered nor admitted into the record in the BPA WP-07 rate proceeding. Nevertheless, issues reflected therein are illustrative of 7(b)(2) issues that must be addressed in future BPA rate cases.)

UNITED STATES OF AMERICA
U.S. DEPARTMENT OF ENERGY
BEFORE THE
BONNEVILLE POWER ADMINISTRATION

2007 Wholesale Power Rate Proceeding	**BPA Docket WP-07**

DIRECT TESTIMONY OF THE PACIFIC NORTHWEST INVESTOR-OWNED UTILITIES

WITNESSES:

W. Scott Brattebo, David W. Hoff, Larry D. La Bolle,
Phil A. Obenchain and L.S. "Pete" Peterson

SUBJECT OF TESTIMONY:

Residential Exchange Program: Section 7(b)(2) Rate Step and
Average System Cost Methodology

January 20, 2006 WP-07-E-JP6-01

CONTENTS

TESTIMONY OF

W. Scott Brattebo, David W. Hoff, Larry D. La Bolle,

Phil A. Obenchain and L.S. "Pete" Peterson

Witnesses for the Pacific Northwest Investor-Owned Utilities

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your names and qualifications.

A. My name is W. Scott Brattebo. I am appearing on behalf of PacifiCorp. My qualifications are as stated in WP-07-Q-JP6-01.

A. My name is David W. Hoff. I am appearing on behalf of Puget Sound Energy, Inc. My qualifications are as stated in WP-07-Q-JP6-02.

A. My name is Larry D. La Bolle. I am appearing on behalf of Avista Corporation. My qualifications are as stated in WP-07-Q-JP6-03.

A. My name is Phil A. Obenchain. I am appearing on behalf of Idaho Power Company. My qualifications are as stated in WP-07-Q-JP6-04.

A. My name is L.S. "Pete" Peterson. I am appearing on behalf of Portland General Electric Company. My qualifications are as stated in WP-07-Q-JP6-05.

Q. What companies are sponsoring this testimony?

A. Avista Corporation, Idaho Power Company, PacifiCorp, Portland General Electric Company and Puget Sound Energy, Inc. (the "Pacific Northwest Investor-Owned Utilities") are sponsoring this testimony.

Q. Please introduce your testimony.

A. We have reviewed the Initial Proposal of the Bonneville Power Administration ("BPA") and address the section 7(b)(2) rate step and the methodology used by BPA to develop Average System Costs ("ASC") of utilities under the 1980 Pacific Northwest Electric Power Planning and Conservation Act (the "Northwest Power Act"). Based on our review, we conclude the following:

1. Section 7(b)(2) Rate Step.

A. **<u>Conservation</u>.** In the 7(b)(2) Case, BPA makes two related errors with respect to conservation. First, BPA ignores load reductions achieved through conservation. Second, BPA ignores substantial conservation costs actually incurred by BPA. The Northwest Power Act neither requires nor allows BPA to ignore these load reductions achieved and costs incurred.

Correcting these errors alone reduces the PF Exchange rate by 28.1 mills/kWh.

B. **<u>Mid-Columbia Resources</u>.** In the 7(b)(2) Case, BPA makes the following errors:

(i) including Mid-Columbia resources in the 7(b)(2) Case resource stack that are not, in fact, "owned . . . by public bodies or cooperatives";

(ii) including Mid-Columbia resources in the 7(b)(2) Case resource stack that are, in fact, "committed to load pursuant to section 5(b)" of the Northwest Power Act; and

(iii) understating costs for Mid-Columbia resources drawn from the 7(b)(2) Case resource stack in determining the projected amounts to be charged in the 7(b)(2) Case (assuming for the sake of argument that such resources were owned by public bodies or cooperatives, were not committed to load pursuant to section 5(b) of the Northwest Power Act and could be included in the 7(b)(2) Case resource stack).

Correcting any one of these errors alone reduces the PF Exchange rate by 27.9 mills/kWh.

C. **<u>Value of Reserve Benefits</u>.** In the 7(b)(2) Case, BPA makes the error of ignoring the substantial reserve benefits provided by BPA's surplus sales in the wholesale power market. BPA erroneously assumes that it receives reserve benefits only from power sales to Direct Service Industrials ("DSIs"). In fact, the reserve benefits provided by BPA power sales in the wholesale power market are superior to those provided by power sales to DSIs.

Correcting this error alone reduces the PF Exchange rate by 30.1 mills/kWh.

D. **Costs of Terminated WNP-1 and WNP-3.** BPA makes the error of failing to subtract from the Program Case, as section 7(g) costs of uncontrollable events, BPA's costs of the terminated WNP-1 and WNP-3. The fact that BPA made a measured, rational response to an uncontrollable event does not and cannot render controllable events such as the Supply System's inability to finance.

Correcting this error alone reduces the PF Exchange rate by 25.8 mills/kWh.

E. **Costs of Financial Reserves for Risk.** BPA makes the error of failing to subtract from the Program Case, as section 7(g) costs of uncontrollable events, any of the Financial Reserves for Risk held by BPA as risk mitigation funds in order to mitigate the impacts of operating and non-operating risks.

Correcting this error alone reduces the PF Exchange rate by up to 17.0 mills/kWh.

F. **Costs of PNRR.** BPA makes the error of failing to subtract from the Program Case, as section 7(g) costs of uncontrollable events, the Planned Net Revenues for Risk ("PNRR"), which BPA includes in its revenue requirement in order to mitigate the impacts of operating and non-operations risks.

Correcting this error alone reduces the PF Exchange rate by 15.5 mills/kWh.

G. **Allocation of Specified Amounts Charged Under Section 7(g).** BPA makes the error of failing to subtract from the Program Case the proper amount of conservation and other specified section 7(g) costs because BPA has failed to properly allocate such costs.

The cumulative effect of correctly allocating the specified section 7(g) costs, including the corrected amounts for costs of uncontrollable events as described in this testimony, reduces the PF Exchange rate by up to 30.1 mills/kWh.

2. The 1984 ASC Methodology.

The 1984 ASC Methodology should be revised to include income taxes and return on equity in the determination of the average system cost of each investor-owned utility. The 1984 ASC Methodology's exclusion of income tax and return on equity was upheld by the Ninth Circuit only as a temporary measure.

Q. How in the Initial Proposal does the proposed PF rate compare to the proposed PF Exchange rate?

A. The average PF rate proposed in the Initial Proposal for the rate period, FY 2007-09, is 31.1 mills/kWh. (WP-07-E-BPA-05A, p. 30, table PF 2007-09.) By contrast, the average PF Exchange rate proposed in the Initial Proposal for the rate period, FY 2007-09, is 69.6 mills/kWh (including 3.4 mills/kWh for transmission). (WP-07-E-BPA-05A, p. 31, table PFx 2007-09.) Thus the average proposed PF Exchange rate exclusive of transmission in the Initial Proposal is more than double the average proposed PF rate, exceeding it by 35.1 mills/kWh:

proposed PF Exchange average rate	69.6 mills/kWh
minus transmission component	– 3.4 mills/kWh
	66.2 mills/kWh
proposed PF Exchange average rate	
exclusive of transmission	66.2 mills/kWh
minus proposed average PF rate	–31.1 mills/kWh
difference	35.1 mills/kWh

This difference far exceeds the comparable difference in the WP-02 proceeding. The base PF Exchange rate adopted in the WP-02 proceeding was only 10.3 mills/kWh higher than the base PF rate adopted in the WP-02 proceeding. (WP-02-FS-BPA-05A, pp. 77, 89.)

II. RESIDENTIAL EXCHANGE PROGRAM SECTION 7(b)(2) RATE STEP

Section 1. Introduction

Q. Please describe BPA's general approach to the section 7(b)(2) rate step.

A. BPA projects in two cases the amounts to be charged for firm power for the combined general requirements for public body, cooperative and federal agency customers over a test period. BPA describes its general approach to the section 7(b)(2) rate step as follows:

> The rate test involves the projection and comparison of two sets of wholesale power rates for the general requirements loads of BPA's public body, cooperative, and Federal agency customers (7(b)(2) or preference customers). The two sets of rates are: (1) a set for the rate filing period (FY 2007–2009) and the ensuing 4 years (FY 2010-2013) assuming that section 7(b)(2) is not in effect (Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (7(b)(2) Case rates). The 7(b)(2) Case rates are modeled the same as the Program Case rates except for the five assumptions listed in section 7(b)(2).

(WP-07-E-BPA-27, p. 2, ll. 15-22.) This general approach is consistent with the general approach described in the following language from the BPA Legal Interpretation:

> *Except for the assumptions specified in section 7(b)(2), all underlying premises will remain constant between the program case and the 7(b)(2) case. Assumptions not specified by the statute will not be considered.* The natural consequence, however, of the 7(b)(2) assumptions will be given full recognition in the modeling of the 7(b)(2) customers' power costs in the 7(b)(2) case.

Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act, 49 Fed. Reg. 23,998 (June 8, 1984) (emphasis added) (the "BPA Legal Interpretation"). Exhibit WP-07-E-JP6-02 submitted herewith is a copy of the

BPA Legal Interpretation.

The projected amounts in the Program Case to be charged these customers for their combined general requirements, "exclusive of amounts charged such customers under [section 7(g) of the Northwest Power Act] for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events" are to be compared to the projected amounts in the 7(b)(2) Case. 16 U.S.C. § 839e(b)(2). To the extent the projected amounts in the Program Case less such section 7(g) amounts are greater than the projected amounts in the 7(b)(2) Case, the rate step is said to have "triggered."

Q. What are the five specified assumptions to be made for the 7(b)(2) Case?

A. BPA must make five specified assumptions in developing the 7(b)(2) Case. BPA must assume that

> (A) the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are—
>
> > (i) served by the Administrator, and
> >
> > (ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives;
>
> (B) public body, cooperative, and Federal agency customers were served, during [the test] period, with Federal base system resources not obligated to other entities under contracts existing as of December 5, 1980, (during the remaining term of such contracts) excluding obligations to direct service industrial customer loads included in subparagraph (A) of this paragraph;
>
> (C) no purchases or sales by the Administrator as provided in section [5(c) of the Northwest Power Act] were made during [the test]

period;

(D) all resources that would have been required, during [the test] period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were—

(i) purchased from such customers by the Administrator pursuant to section [6 of the Northwest Power Act], or

(ii) not committed to load pursuant to section 839c(b) of this title [5(b) of the Northwest Power Act],

and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator; and

(E) the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from—

(i) reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal base system resources, identified under subparagraph (D) of this paragraph, and

(ii) reserve benefits as a result of the Administrator's actions under [the Northwest Power Act] were not achieved.

16 U.S.C. § 839e(b)(2).

Q. Please summarize the effect of correcting the errors summarized above.

A. Correcting the errors summarized above in our testimony regarding the section 7(b)(2) rate step would eliminate the 7(b)(2) trigger amount and reduce the PF Exchange rate by 31.6 mills/kWh (from the 69.6 mills/kWh PF Exchange rate in the Initial Proposal to 38.0 mills/kWh). Reducing the PF Exchange rate by 31.6 mills/kWh by making these corrections in the section 7(b)(2) rate step and applying this reduced PF Exchange rate to the residential and small-farm loads and average system costs projected by BPA in this proceeding would increase projected average residential exchange benefits to $443.4 million per year, of which $363.9 million per year would be for residential and small-farm customers of the investor-owned utilities. *This level of benefits is projected under a properly performed section 7(b)(2) rate step even with no BPA sales to the DSIs.*

Because the effect of correcting the errors in the section 7(b)(2) rate step discussed below are generally additive until the trigger amount is eliminated, incorporating, for example, two or more of the larger corrections will eliminate the trigger and produce these projected average residential exchange benefits. For example, the combined effect of making our corrections to (i) the conservation errors in the 7(b)(2) Case and (ii) the inclusion of the Mid-Columbia resources in the 7(b)(2) Case resource stack would eliminate the 7(b)(2) trigger amount and reduce the PF Exchange rate by 31.6 mills/kWh (from the 69.6 mills/kWh PF Exchange rate in the Initial Proposal to 38.0 mills/kWh).

The average annual effect of correcting each of the various section 7(b)(2) rate step errors during the FY2007-FY2009 rate period is as follows:

Projected Average Annual Effects of Corrections
FY2007-FY2009 Rate Period

Correction	7(b)(2) Projected Average Annual Benefits for Residential and Small-Farm Customers of IOUs ($million)	7(b)(2) Projected Average Annual Benefits for Residential and Small-Farm Customers of IOUs and Preference Agencies ($million)	7(b)(2) Projected Average PF Exchange Rate (mills/kWh)
1. Conservation in the 7(b)(2) Case	$207.7	$260.4	41.5
2. The Mid-Columbia Resources in the 7(b)(2) Case Resource Stack	$198.3	$249.2	41.7
3. Valuation of Reserve Benefits	$297.3	$365.6	39.5
4. Costs of Uncontrollable Events (Termination of WNP-1 and WNP-3)	$110.6	$145.5	43.8
5. Costs of Uncontrollable Events (Costs of Financial Reserves for Risk)	$32.7	$37.8	52.6
6. Costs of Uncontrollable Events (Costs of PNRR)	$28.1	$32.3	54.1
7. Allocation of Amounts Charged Under Section 7(g)*	$297.3	$365.6	39.5
Effect of All Corrections (Zero "Trigger Amount")	**$363.9**	**$443.4**	**38.0**

* Amounts reflect cumulative effects of correctly allocating the specified section 7(g) costs, including the corrected amounts on lines 4, 5 and 6.

Making these corrections would dramatically reduce BPA's proposed PF Exchange rate of 69.6 mills/kWh.

Moreover, the effect of correcting each of the section 7(b)(2) rate step errors increases over time. For example, the effect of the above corrections for FY2013 is as follows:

Projected Annual Effects of Corrections
FY2013

Correction	7(b)(2) Projected Annual Benefits for Residential and Small-Farm Customers of IOUs ($million)	7(b)(2) Projected Annual Benefits for Residential and Small-Farm Customers of IOUs and Preference Agencies ($million)	7(b)(2) Projected PF Exchange Rate (mills/kWh)
1. Conservation in the 7(b)(2) Case	$355.6	$414.8	45.9
2. The Mid-Columbia Resources in the 7(b)(2) Case Resource Stack	$344.9	$402.3	46.1
3. Valuation of Reserve Benefits	$452.0	$527.3	43.9
4. Costs of Uncontrollable Events (Termination of WNP-1 and WNP-3)	$191.6	$239.3	47.2
5. Costs of Uncontrollable Events (Costs of Financial Reserves for Risk)	$54.2	$62.2	53.8
6. Costs of Uncontrollable Events (Costs of PNRR)	$49.3	$56.4	55.2
7. Allocation of Amounts Charged Under Section 7(g)*	$452.0	$527.3	43.9
Effect of All Corrections (Zero "Trigger Amount")	**$521.7**	**$608.5**	**42.5**

* Amounts reflect cumulative effects of correctly allocating the specified section 7(g) costs, including the corrected amounts on lines 4, 5 and 6.

The effects presented in this testimony of correcting BPA's errors do not include the effects of increases in the projected average system costs due to correcting the 1984 ASC Methodology to include income taxes and return on equity.

Section 2. Conservation

Q. Please summarize your testimony regarding BPA's treatment of conservation costs and load reductions in the 7(b)(2) Case.

A. In the 7(b)(2) Case, BPA makes two related errors with respect to conservation. First, BPA ignores load reductions achieved through conservation. Second, BPA ignores substantial conservation costs actually incurred by BPA. The Northwest Power Act neither requires nor allows BPA to ignore these load reductions achieved and costs incurred.

Correcting these errors alone reduces the PF Exchange rate by 28.1 mills/kWh.

Q. What is your understanding of the "amounts to be charged" that are to be projected in the Program Case and the 7(b)(2) Case?

A. For each of these two cases, BPA is required to project the amount to be charged, over the test period, which in this case is FY 2007-13 (the "Test Period"), for firm power for the *combined general requirements* of public body, cooperative and federal agency customers.

Q. How is "general requirements" defined for purposes of section 7 of the Northwest Power Act?

A. Section 7(b)(4) of the Northwest Power Act defines, for purposes of section 7 of the Northwest Power Act, "general requirements" as "the public body, cooperative or Federal agency customer's electric power purchased from the Administrator under section [5(b) of the Northwest Power Act], exclusive of any new large single load."

Q. Under the Northwest Power Act, how is conservation required to be treated in determining general requirements?

A. General requirements are an amount of power that can be purchased from BPA under section 5(b) to meet loads. To the extent conservation reduces those loads, conservation reduces the amount of power that can be purchased under section 5(b).

The loads to be used in determining general requirements are the Program Case *loads*, not the Program Case loads that would have occurred in the absence of conservation. The amount of power that can be purchased by a utility under section 5(b) of the Northwest Power Act is limited to the amount by which the utility's firm power load in the region exceeds its resources used to serve its firm load in the region. This amount of power that the utility can purchase from BPA under section 5(b) is inherently lower as a result of conservation. This is true for both the Program Case and the 7(b)(2) Case. Thus the combined general requirements projected for both the Program Case and the 7(b)(2) Case should reflect, and be reduced by, the load reduction effects of conservation.

The combined general requirements projected for the 7(b)(2) Case must equal those projected for the Program Case, except to the extent a modification in the projection of the combined general requirements is required by one of the five specified assumptions (or their natural consequences).

Q. Do any of the five specified assumptions (or their natural consequences) require that the combined general requirements projected for the Program Case be modified as a result of conservation in determining the combined general requirements projected for the 7(b)(2) Case?

A. No.

Q. Do any of the five assumptions specified in section 7(b)(2) require BPA to include less conservation *costs* in the projected amounts to be charged in the 7(b)(2) Case than the conservation *costs* BPA has incurred or has projected to incur?

A. No, there is no such requirement in the Northwest Power Act. BPA erroneously, and without adequate explanation, failed to include all conservation costs in the projected amounts to be charged in the 7(b)(2) Case that were included in the projected amounts to be charged in the Program Case.

Q. How do the combined general requirements projected in the Program Case compare with those projected in the 7(b)(2) Case?

A. In developing the 7(b)(2) Case, BPA took the combined general requirements from the Program Case and erroneously added 796 aMW of additional load. (*See* WP-07-E-BPA-27, p. 13, ll. 17-20.) Thus, for purposes of the 7(b)(2) Case, BPA assumed that the combined general requirements would be increased by a load roughly equivalent to a load the size of Portland, Oregon—distorting the projected costs of the 7(b)(2) Case.

Q. Please summarize BPA's treatment of conservation costs and load reductions in the 7(b)(2) Case.

A. BPA improperly assumes that (i) BPA conservation costs may be deducted from the 7(b)(2) Case and (ii) load reductions may be ignored in determining the combined general requirements in the 7(b)(2) Case:

1. BPA's Program Case projects amounts to be charged that include $197.8 million of average annual conservation costs over the Test Period. (WP-07-E-BPA-06A, pp. 10-16, l. 18.) However, BPA's 7(b)(2) Case in

effect includes only $39 million of average annual conservation costs over the Test Period.

2. BPA's Program Case projects combined general requirements that, by the end of the Test Period, are 1,389 aMW lower than would have occurred in the absence of conservation. (WP-07-E-BPA-06, pp. D-16, D-19.) However, BPA's 7(b)(2) Case in effect includes only 208 aMW of average annual BPA conservation by the end of the Test Period.

This results from BPA's only selecting ("drawing") 208 aMW of BPA conservation from the 7(b)(2) Case resource stack.

Q. Have you analyzed the effect of correcting BPA's erroneous addition of 796 aMW to the projected load in the 7(b)(2) Case and erroneous exclusion of BPA conservation costs in the 7(b)(2) Case?

A. Yes. Correcting these two errors alone would reduce the PF Exchange rate by 28.1 mills/kWh, from the 69.6 mills/kWh PF Exchange rate in the Initial Proposal to 41.5 mills/kWh. Reducing the PF Exchange rate by 28.1 mills/kWh by making these corrections in the section 7(b)(2) rate step and applying this reduced PF Exchange rate to the residential and small-farm loads and average system costs projected by BPA in this proceeding would increase projected average residential exchange benefits to $260.3 million per year, of which $207.7 million per year would be for residential and small-farm customers of the investor-owned utilities.

The effect of such corrections was analyzed by modifying the Initial Proposal's RAM2007 model. Such modifications are described in Exhibits WP-07-E-JP6-03 and WP-07-E-JP6-04 submitted herewith. To minimize the modeling changes necessary to analyze such corrections, we did not modify BPA's 7(b)(2) Case combined general requirements and did not directly add conservation costs per se. Rather, the model was modified such that the conservation in the 7(b)(2) Case resource stack was picked first and the costs of such conservation were thereby included in the projected amounts to be charged. Doing this produced modeling results equivalent to (i) using combined general requirements in the 7(b)(2) Case that properly reflect the load reduction effects of conservation, and (ii) including in the projected amounts to be charged in the 7(b)(2) Case some (but not necessarily all) of the costs of such conservation.

Q. Is the treatment of conservation and its costs that you recommend above consistent with the BPA Legal Interpretation?

A. Yes. As discussed above, the BPA Legal Interpretation concludes that the Program Case is to be modified only by the five assumptions specified in section 7(b)(2) (or their natural consequences) in developing the 7(b)(2) Case. A different treatment of conservation is not one of the five assumptions (or their natural consequences).

Q. Is the treatment of conservation and its costs that you recommend above consistent with the 1984 Implementation Methodology?

A. No. We recommend treating conservation and its costs the same in the Program Case and the 7(b)(2) Case because different treatment of conservation and its costs is not one of the five specified assumptions (or their natural consequences). As discussed above, the BPA Legal Interpretation states that the 7(b)(2) Case must be developed by modifying the Program Case by the five specified assumptions (and their natural consequences) only. However, the Section 7(b)(2) Implementation Methodology, BPA File No. 7(b)(2)-84 (the "1984 Implementation Methodology") states that the Program Case must be modified by assumptions with respect to conservation and conservation costs that are not included in any of the five assumptions specified in section 7(b)(2) (or their natural consequences) in developing the 7(b)(2) Case. Exhibit WP-07-E-JP6-05 submitted herewith is a copy of the 1984 Implementation Methodology.

The 1984 Implementation Methodology cryptically and without adequate explanation calls for the combined general requirements in the Program Case to be increased by conservation savings in developing the combined general requirements in the 7(b)(2) Case:

> The initial loads will be used in the 7(b)(2) case will be same as those used in the program case, except that they will not include estimates of programmatic conservation savings.

1984 Implementation Methodology, Ex. C at 41. Similarly, the 1984 Implementation Methodology states that the

> costs of billing credits and conservation, although appearing in the [projected amounts to be charged in the Program Case], are not necessarily included in the projected amounts to be charged in the 7(b)(2) Case. This is because billing credits and programmatic conservation are added to the resources used to serve the 7(b)(2) customers only to the extent that they are needed after the FBS [Federal base system] is exhausted and only in the event that they are the least-cost resources to be added. If the FBS is sufficient to serve the 7(b)(2) load, or other available additional resources have lower costs, then billing credits and programmatic conservation will not be added to the 7(b)(2) case.

1984 Implementation Methodology at 5.

With respect to conservation, the 1984 Implementation Methodology is inconsistent with section 7(b)(2) and cannot be relied upon.

Q. Has BPA concluded that it has the discretion to revise the 1984 Implementation Methodology?

A. Yes. In the BPA Legal Interpretation, BPA concluded that section 7(b)(2)

> is a clear grant of discretion to the Administrator to determine the manner in which the five assumptions of section 7(b)(2) are applied and the rate test is implemented. However, BPA recognizes that the reasonableness and methodologies used to implement section 7(b)(2) will be tested in the relevant rate [cases].

BPA Legal Interpretation at 24,000.

Section 3. Mid-Columbia Resources in the 7(b)(2) Case Resource Stack

Q. Please summarize your testimony regarding BPA's inclusion and pricing of Mid-Columbia resources in the 7(b)(2) Case resource stack.

A. In the 7(b)(2) Case, BPA makes the following errors:

(i) including Mid-Columbia resources in the 7(b)(2) Case resource stack that are not, in fact, "owned . . . by public bodies or cooperatives";

(ii) including Mid-Columbia resources in the 7(b)(2) Case resource stack that are, in fact, "committed to load pursuant to section 5(b)" of the Northwest Power Act; and

(iii) understating costs for Mid-Columbia resources drawn from the 7(b)(2) Case resource stack in determining the projected amounts to be charged in the 7(b)(2) Case (assuming for the sake of argument that such resources were owned by public bodies or cooperatives, were not committed to load pursuant to section 5(b) of the Northwest Power Act and could be included in the 7(b)(2) Case resource stack).

Correcting any one of these errors alone reduces the PF Exchange rate by 27.9 mills/kWh.

Q. What is your understanding of the resources that must be included in the 7(b)(2) Case resource stack?

A. Section 7(b)(2)(D) of the Northwest Power Act states that

> all resources that would have been required, during [the test] period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were—
>
> (i) purchased from such customers by the Administrator pursuant to section [6 of the Northwest Power Act], or
>
> (ii) not committed to load pursuant to section [5(b) of the Northwest Power Act],
>
> and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator . . . .

16 U.S.C. § 839e(b)(2)(D). Thus the projected amounts to be charged in the 7(b)(2) Case must be determined assuming that the combined general requirements in such case are met first with available federal base system resources and then from a "resource stack." The last resource to be drawn (if needed) from the resource stack after it is otherwise exhausted is a generic resource to be priced at the "average cost of all other new resources acquired by [BPA]." (BPA concluded it did not need to draw this generic resource in the Initial Proposal.)

Q. What Mid-Columbia resources did BPA assume were included in the 7(b)(2) Case resource stack?

A. BPA projected that, during the Test Period, 846 aMW of Mid-Columbia resources (the

"Mid-Columbia resources") would be sold to investor-owned utilities in the region, and erroneously included the Mid-Columbia resources in the 7(b)(2) resource stack. (WP-07-E-BPA-06, p. C-3.) In projecting the amounts to be charged in the 7(b)(2) Case, BPA assumed the Mid-Columbia resources were (i) owned during the Test Period by the public body owners of the Mid-Columbia projects and available during the Test Period to meet public body and cooperative loads, (ii) not dedicated under section 5(b) of the Northwest Power Act during the Test Period to the regional loads of the public bodies or cooperatives, and (iii) available during the Test Period to BPA at the projected cost of the Mid-Columbia resources to the public body owners of the Mid-Columbia dams. As discussed below, items (i) and (iii) of these BPA assumptions are incorrect, and item (ii) of these BPA assumptions applies the wrong test under the statute.

Under section 3(19) of the Northwest Power Act, these resources cannot be classified as "owned" for purposes of the 7(b)(2) Case because the preference utilities that own the Mid-Columbia dams do not have rights to the power from such dams sold to investor-owned utilities during the Test Period. Section 3(19) of the Northwest Power Act defines "resource" with respect to power and generating facilities—not as the physical generating facilities themselves—but rather as "electric power, including the actual or planned electric power capability of generating facilities." 16. U.S.C. § 839a(19)(A). Therefore, the "resource" with respect to physical generating facilities owned by public bodies or cooperatives, such as the Mid-Columbia dams, is, for purposes of the Northwest Power Act, the *power* from those projects, rather than the *projects* themselves. The power from the Mid-Columbia dams included in the 7(b)(2) Case resource is being sold, and is projected during the Test Period by BPA as sold, to the investor-owned utilities in the region. It therefore cannot be considered as a resource owned or purchased by public bodies or cooperatives. Accordingly, BPA's assumption that this power will be owned during the Test Period by public bodies or cooperatives and available to meet their loads is wrong, and the Mid-Columbia resources should not be included in the 7(b)(2) Case resource stack.

Q. Should BPA assume that the Mid-Columbia resources are committed to load during the Test Period pursuant to section 5(b) of the Northwest Power Act?

A. Yes. The Mid-Columbia resources cannot be included in the 7(b)(2) Case resource stack. Such resources are committed to the firm power loads of the investor-owned utilities pursuant to section 5(b) of the Northwest Power Act.

BPA, however, concluded that power from the Mid-Columbia dams sold to regional investor-owned utilities is a "non-dedicated resource," and therefore available to serve preference loads in the 7(b)(2) Case. (Keep *et al.*, WP-07-E-BPA-27, pp. 14-17.) This conclusion is erroneous and contrary to the Northwest Power Act, and is another reason the Mid-Columbia resources should not be included in the 7(b)(2) Case resource stack.

The relevant section 7(b)(2) statutory language (in (D)(ii) thereof) is "resources not committed to load pursuant to section 5(b)." In other words, a resource may not be included in the 7(b)(2) Case resource stack if it is "committed to load pursuant to section 5(b)." Section 5(b) addresses the "firm power load of . . . [any] public body, cooperative or *investor-owned utility* in the Region" and the commitment by any such "public body, cooperative or *investor-owned utility* in the Region" of resources to its firm load in the Region. 16 U.S.C. § 839c(b) (emphasis added). In short, section 5(b) addresses both resources committed to the loads of preference customers and resources committed to the loads of investor-owned utilities. Reading this section 7(b)(2) and section 5 language together demonstrates that resources committed to investor-owned utility loads pursuant to section 5(b) cannot be "resources not committed to load pursuant to section 5(b)."

BPA has interpreted the "not committed to load pursuant to section 5(b)" statutory provision as meaning "'resources owned or purchased by the 7(b)(2) customers, and not dedicated to *their own* loads.'" (Keep *et al.*, WP-07-E-BPA-27, pp. 14, ll. 21-22 (emphasis added).) This is an erroneous interpretation. In reaching this erroneous interpretation, BPA cites the following language from the BPA Legal Interpretation:

> Section 7(b(2)(D)(ii) describes the second type of resources as those "not committed to load pursuant to section 5(b)." These are resources owned or purchased by the 7(b)(2) customers [public bodies, cooperatives and Federal agencies] that are not dedicated to their own loads.

BPA Legal Interpretation at 24,005. This cited language misinterprets section 7(b)(2).

BPA's misinterpretation of "not committed to load" to mean "not committed to *preference* load" in the Initial Proposal and in the BPA Legal Interpretation ignores the plain language of section 5(b), which, as discussed above, makes no distinction between the loads of preference customers and the loads of investor-owned utilities. The Mid-Columbia resources should not be included in the 7(b)(2) Case resource stack because they are committed to load pursuant to section 5(b).

Q. Has BPA always misinterpreted "not committed to load" to mean "not committed to *preference* load" in BPA's rate cases?

A. No. This misinterpretation is relatively new in BPA's rate cases and has been used only for the two most recent BPA power cases (WP-96 and WP-02). (Keep *et al.*, WP-07-E-BPA-27, p.15, ll. 16-20.) In both of these cases, this misinterpretation had a negligible effect.

Q. Has BPA described the effect of including Mid-Columbia resources that are committed to serve investor-owned utility load in the 7(b)(2) Case resource stack in this rate case?

A. BPA states that "this will be the first time that, as a practical matter, our approach to the issue has significantly influenced the section 7(b)(2) Rate Test to increase the PF Exchange rate." (Keep *et al.*, WP-07-E-BPA-27, p. 15, ll. 4-6.)

Q. Assuming, for the sake of argument, that the Mid-Columbia resources were properly included in the 7(b)(2) resource stack, has BPA properly identified the cost of this power in such stack?

A. No. BPA has understated the cost at which such resources could be acquired for purposes of the 7(b)(2) Case. BPA should not include the Mid-Columbia resources in the 7(b)(2) Case resource stack (assuming for the sake of argument they could be included at all) at a cost less than the projected market price of power.

The 7(b)(2) Case must develop projected amounts to be charged, including amounts to be charged to collect the costs of acquiring resources from the resource stack. Therefore, the relevant cost to include in the 7(b)(2) Case resource stack is the projected cost to BPA to acquire the resources in the stack. There is no basis to assume that the rights of the investor-owned utilities to the Mid-Columbia resources could be bought from them at a price less than market.

Q. Please summarize the corrections that BPA should make to address the errors described above regarding Mid-Columbia resources in the 7(b)(2) Case resource stack.

A. BPA should make the following corrections in order to correct the errors described above regarding the Mid-Columbia resources in the 7(b)(2) Case resource stack:

(i) remove the Mid-Columbia resources from the 7(b)(2) Case resource stack because they are not, in fact, "owned . . . by public bodies or cooperatives"; or

(ii) remove the Mid-Columbia resources from the 7(b)(2) Case resource stack because they are, in fact, "committed to load pursuant to section 5(b)" of the Northwest Power Act; or

(iii) change the projected cost of the Mid-Columbia resources in the 7(b)(2) Case resource stack to projected market prices (assuming for the sake of argument such resources were owned by public bodies or cooperatives, were not committed to load pursuant to section 5(b) of the Northwest Power Act and could be included in the 7(b)(2) Case resource stack).

Q. Have you analyzed the effect of correcting the errors you describe above regarding Mid-Columbia resources in the 7(b)(2) Case resource stack?

A. Yes. Making any one of these corrections alone would reduce the PF Exchange rate by 27.9 mills/kWh, from the 69.6 mills/kWh PF Exchange rate in the Initial Proposal to 41.7 mills/kWh. Reducing the PF Exchange rate by 27.9 mills/kWh by making any of these corrections in the section 7(b)(2) rate step and applying this reduced PF Exchange rate to the residential and small-farm loads and average system costs projected by BPA in this proceeding would increase projected average residential exchange benefits to $249.2 million per year, of which $198.3 million per year would be for residential and small-farm customers of the investor-owned utilities.

Section 4. Valuation of Reserve Benefits

Q. Please summarize your testimony regarding the reserve benefits provided by BPA's surplus sales in the wholesale power market.

A. In the 7(b)(2) Case, BPA makes the error of ignoring the substantial reserve benefits provided by BPA's surplus sales in the wholesale power market. BPA erroneously assumes that it receives reserve benefits only from power sales to DSIs. In fact, the reserve benefits provided by BPA power sales in the wholesale power market are superior to those provided by power sales to DSIs.

Correcting this error alone reduces the PF Exchange rate by 30.1 mills/kWh.

Q. Please summarize the role of reserves in the 7(b)(2) Case.

A. BPA, in the 7(b)(2) Case, must project the amounts to be charged for firm power for the combined general requirements for public body, cooperative and federal agency customers over the Test Period. In making such projections, BPA must make five assumptions in adjusting the Program Case to the 7(b)(2) Case, including the following assumption with respect to BPA's reserve benefits:

> (E) the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from—
>
> > (i) reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal base system resources, identified under subparagraph (D) of this paragraph, and
> >
> > (ii) reserve benefits as a result of the Administrator's actions under [the Northwest Power Act]
>
> were not achieved.

16 U.S.C. § 839e(b)(2)(E). The Northwest Power Act definition of "reserves" does not limit "reserves" to those from any particular source, DSIs or otherwise.

Under the statutory language quoted above, BPA must project in the 7(b)(2) Case the quantifiable monetary savings, during the Test Period, to public body, cooperative and federal agency customers resulting from reserve benefits achieved as a result of the Administrator's actions under the Northwest Power Act. Such projected reserve benefits are typically referred to as the "value of reserves" or "reserve benefits." Because BPA's reserve benefits are assumed not to be achieved in the 7(b)(2) Case, the amount of the reserve benefits is added as a charge to the projected amounts to be charged that are developed in the 7(b)(2) Case before they are compared to the projected amounts to be charged that are developed in the Program Case.

Q. Are "reserves" defined in the Northwest Power Act?

A. Yes. Section 3(17) of the Northwest Power Act states:

> "Reserves" means the electric power needed to avert particular planning or operating shortages for the benefit of firm power customers of the Administrator and available to the Administrator (A) from resources or

> (B) from rights to interrupt, curtail, or otherwise withdraw, as provided by specific contract provisions, portions of the electric power supplied to customers.

16 U.S.C. § 839a(17). Planning or operating shortages that BPA might experience could be caused for example by low or critical streamflow conditions, delayed completion or unexpectedly poor performance of regional generating resources or conservation measures, and the unanticipated growth of regional firm loads. This was true in 1980 and remains true today. BPA is no worse off today in terms of reserves because of the diminishment of DSI load; indeed, BPA reserves from its surplus power sales in the wholesale power market are superior in several respects to those from its sales to DSIs.

The Senate Committee on Energy and Natural Resources Report states as follows regarding the purpose and role of reserves under the Northwest Power Act:

> to protect firm loads for any reason, including low or critical streamflow conditions, and . . . to protect firm loads against the delayed completition [sic] or unexpectedly poor performance of regional generating resources or conservation measures, and against the unanticipated growth of regional firm loads. . . .

U.S. Senate Committee on Energy and Natural Resources Report No. 96-272 at 28.

Reserves were contemplated to be provided through a right to interrupt power sales in order to protect and benefit firm power sales to BPA's utility customers in the region for various reasons—such as unanticipated growth of regional firm loads, delayed completion or poor performance of regional generating resources and low streamflows.

Q. Are reserves under the Northwest Power Act limited to reserves arising from BPA power sales to DSIs?

A. No. As discussed above, the Northwest Power Act does not state that "reserves" are limited to any particular source, DSIs or otherwise. Indeed, section 5(d)(1)(A) of the Northwest Power Act states as follows:

> The Administrator is authorized to sell in accordance with this subsection electric power to existing direct service industrial customers. Such sales provide a *portion of the Administrator's reserves for firm power loads* within the region.

16 U.S.C. § 839c(d)(1)(A) (emphasis added). In other words, BPA's rights to interrupt power sales to the DSIs to protect and benefit firm power sales to BPA's utility customers in the region are, or were, not to be the exclusive source of BPA's reserves under the Northwest Power Act.

Q. Please explain how BPA surplus sales in the wholesale power market meet this definition of "reserves" under the Northwest Power Act.

A. BPA establishes contract provisions for surplus sales in the wholesale power market to benefit—and avoid having those power sales pose service and cost risks to BPA's firm power load in the region under sections 5(b), 5(c) and 5(d) of the Northwest Power Act. In this manner, BPA's surplus sales protect and benefit BPA sales for such firm power loads. Typically, BPA does this by controlling, through the terms of its surplus power sales in the wholesale power market, the term for which those sales are made.

Q. Does BPA make surplus sales in the wholesale power market under the Northwest Power Act?

A. Yes, such sales are to be made pursuant to section 5(f) of the Northwest Power Act:

> [BPA] is authorized to sell, or otherwise dispose of, electric power, including power acquired pursuant to [the Northwest Power Act] and other Acts, that is surplus to [BPA's] obligations . . . .

16 U.S.C. § 839c(f).

BPA's testimony demonstrates that BPA surplus sales in the wholesale market, such as those under the proposed FPS-07 rate schedule, are made under the Northwest Power Act and constitute reserves (and provide reserve benefits) as contemplated by the Northwest Power Act and its legislative history. BPA has proposed the FPS-07 rate in this proceeding for its surplus power sales in the wholesale power market:

> BPA has sold, and will continue to sell, secondary energy in the real-time, day-ahead, balance-of-month and forward electricity markets. BPA engages in sales (and purchase) transactions with most of the major participants in the West Coast wholesale energy market. Like other market participants, BPA, in all of the aforementioned transactions, adheres to Western Systems Power Pool (WSPP) contract terms and conditions, which reflect industry standards. The proposed FPS-07 rate will be used in all of the transactions just described.

(WP-07-E-BPA-26, p. 5, ll. 10-16.) BPA describes the purpose of the FPS-07 rate schedule as follows:

> BPA developed the FPS-07 rate schedule to replace the FPS-96R rate schedule which expires on September 30, 2006. As with the FPS-96R rate schedule, BPA's overall objective of the FPS-07 rate schedule is to provide BPA with a degree of flexibility so that it can effectively market surplus firm energy from the Federal Columbia River Power System (FCRPS) in the West Coast wholesale energy market.

> Factors such as weather, time of year, and fish and wildlife constraints cause generation levels available from BPA's hydro-based system to vary widely from year-to-year, month-to-month and even day-to-day. In addition to this wide variation in BPA's surplus energy amounts, BPA must manage variations in load. As a consequence of these competing factors, BPA must routinely participate in the West Coast wholesale market - both selling power when a surplus exists, and buying to make up any shortfalls.
>
> Since BPA periodically finds itself purchasing power in the West Coast wholesale market to manage deficits, it is imperative that BPA also be able to sell at the going price in that same wholesale market. In order for BPA to avoid "buying high and selling low," FPS-07 must be a true market-based rate schedule that is not constrained by cost-based limitations.
>
> . . . .
>
> At least as early as the 1987 Wholesale Power and Transmission Rate Proceeding (WP-87), the Administrator concluded that he had the authority to establish a type of market-based rate. *See,* WP-87-A-02, at 242-251 (discussing the Market Transmission rate, MT-87). Later, in the WP-96 rate case, BPA pointed out that section 7(e) of the Northwest Power Act grants the Administrator considerable rate design discretion, including the ability to employ rate designs that use a market-based approach. *See,* WP-96-A-02, at 457. The Agency further found that section 7(e) and its legislative history make clear that BPA's cost allocation directives concern the amount of revenues to be recovered from customer classes, and not the design of the rates to recover those revenues. *Id.* at 458. Therefore, in the aggregate, BPA's rates must be, and are, designed to recover BPA's total costs.
>
> The proposed FPS-07 rate schedule, like its predecessors the FPS-96 and FPS-96R rate schedules, provides BPA with improved assurance of cost recovery and an enhanced ability to keep rates low. Revenues under the FPS-07 rate schedule are credited against BPA's revenue requirement and, as such, FPS-07 will serve as one component of BPA's overall rate structure to ensure that, in the aggregate, BPA recovers its overall costs.

(WP-07-E-BPA-26, p. 3, l. 8 through p. 4, l. 23.)

Reserves include BPA's rights to interrupt, curtail or otherwise withdraw sales of surplus power when necessary. BPA may establish these rights through contractual recall provisions or through power sales for limited terms (*e.g.*, hour ahead, hourly, day ahead, balance of week, balance of month, monthly and seasonal). This ensures that such BPA surplus power sales benefit and do not pose service and cost risks to BPA's firm power load in the region under sections 5(b), 5(c) and 5(d) of the Northwest Power Act.

BPA's "secondary market" or "surplus" power sales in the wholesale power market meet the definition of "reserves" under the Northwest Power Act and fulfill the purposes contemplated for BPA reserves under the Northwest Power Act. As discussed below, these BPA "secondary market" or "surplus" power sales are substantial.

Q. Can you provide examples of BPA's recall or withdrawal of surplus power from the wholesale power markets when needed to serve BPA's firm loads?

A. Yes. BPA has exercised recall rights under contracts and has not renewed surplus sales in the wholesale power market when the power was needed to serve BPA's firm loads. For example:

> With the Northwest facing power shortages as early as this winter, BPA is giving notice to its California customers that long-term contracts for surplus and excess federal power sales will not be renewed. Where contracts have recall or conversion rights, BPA is exercising those rights. BPA sold several hundred megawatts of power to California when the Northwest had surplus and excess power.
>
> By law, BPA is directed to sell outside the Northwest only power that is surplus to the region's needs. Buyers have different rights under each contract. Where contract terms allow, BPA can convert energy sales into capacity exchanges or give notice of termination. In contracts that contain no recall or conversion provisions, BPA is notifying California buyers that contracts will not be renewed.

"BPA Recalls California Contracts," BPA Journal (Oct. 2000) at page 3.

> When the cold snap hit, BPA reduced its surplus sales to meet required loads in the Northwest. BPA structures surplus sales to gain revenue while retaining the ability to recall the power when it is needed. Revenue gained from selling surplus power is used to offset power purchases when Northwest loads exceed BPA capacity.

"Power Demand Soars as Temperatures Plummet," BPA Press Release (Feb. 2, 1996) at page 1.

More fundamentally, BPA maintains its right to recall or withdraw power from the wholesale power market by controlling the duration of such sales. As discussed above, BPA may establish these rights through contractual recall provisions or power sales for limited terms (*e.g.*, hour ahead, hourly, day ahead, balance of week, balance of month, monthly and seasonal) to ensure that BPA's access to that power when needed to serve its firm power customers is not unduly impeded.

Q. Please summarize BPA's treatment of reserves in the 7(b)(2) Case.

A. BPA made no adjustment to the projected amounts to be charged in the 7(b)(2) Case for reserves.

Q. How should reserve benefits be determined in the 7(b)(2) Case?

A. BPA makes extensive surplus power sales at market prices in the wholesale power market. These sales provide reserve benefits to BPA (particularly in the absence of BPA sales to DSIs). Accordingly, BPA should recognize and treat these surplus power sales at market prices as providing reserve benefits in the 7(b)(2) Case.

Q. Is treating BPA wholesale power market sales as "reserves" in the 7(b)(2) Case addressed in the BPA Legal Interpretation or the 1984 Implementation Methodology?

A. The BPA Legal Interpretation does not address the language of section 7(b)(2) relating to "reserve benefits." The 1984 Implementation Methodology discusses determining reserve benefits based on BPA's restriction rights on DSI loads but does not discuss or specifically reject treating BPA wholesale power market sales as providing "reserve benefits" in the 7(b)(2) Case. This is not surprising given the BPA sales to DSIs in 1984.

Q. Have you estimated the reserve benefits over the Test Period provided by BPA's projected surplus power sales at market prices?

A. Yes. We analyzed the amount of secondary revenues from surplus sales in the wholesale power market at market prices that BPA is projecting in the Test Period. BPA is projecting revenue from short-term market sales to average about $576 million per year during the FY2007-09 rate period:

> Revenue from short-term market sales is projected to average about $576 million per year during the FY 2007-2009 rate period. *See,* WPRDS Documentation, Section 3.6.1 and Section 3.6.2, WP-07-E-BPA-05A.

(WP-07-E-BPA-05, p. 110, ll. 5-6.)

These projected secondary revenues of $576 million per year are gross revenues. In valuing BPA's reserve benefits, these secondary revenues should not, for purposes of determining reserve benefits, be reduced by the projected cost of BPA's secondary purchases ($87.6 million per year). In the Initial Proposal, BPA projects secondary purchases only when it does not project secondary sales (*i.e.*, projects secondary purchases it needs to meet its firm loads). BPA consistently (i) projects no secondary purchases for months for which it projects secondary sales and (ii) projects no secondary sales for months for which it projects secondary purchases. (WP-07-E-BPA-05A, pp. 160-195, tables 3.8.1 & 3.8.2.)

BPA secondary sales benefit BPA's firm power load in the region under sections 5(b), 5(c) and 5(d) of the Northwest Power Act. BPA's projected secondary sales are analogous to having interruptible customers that can be curtailed to benefit and protect BPA's firm power loads. The value of reserve benefits provided by BPA's secondary sales in the wholesale market is equal to the projected revenues from such sales reduced by BPA's incremental cost for such sales because BPA's revenue requirement would be increased by that amount in the absence of such reserves. Because that incremental cost for such sales is negligible, the value of reserve benefits is equal to the revenues from BPA secondary sales in the wholesale power market, or $576 million as projected by BPA in the Initial Proposal.

Q. How does your recommended method of valuing reserve benefits compare with BPA's historical approach?

A. Our recommended valuation method is different from the valuation method used by BPA to value reserve benefits provided by the relatively limited withdrawal and interruption rights provided under the DSI contracts. BPA generally evaluated those limited withdrawal and interruption rights using the capital costs, fixed operation and maintenance costs and operating costs of an incremental resource (combined-cycle combustion turbines) to determine the avoided cost of "firming up" service to the DSI load. In doing so, BPA included various of these costs depending on the particular interruption or withdrawal right under the DSI contract being evaluated. Particularly given the relatively limited interruption or withdrawal rights under the DSI contracts, it may well have made sense to value reserve benefits by looking to the avoided cost of "firming up" service to the DSI loads through combined-cycle combustion turbines.

Use of BPA's traditional method of calculating reserve benefits in order to value reserve benefits provided by BPA surplus sales in the wholesale power market would be conservative. This is because such use essentially assumes that reserve benefits provided by BPA surplus sales in the wholesale power market are equivalent to those previously provided by BPA power sales to DSIs. The reserves provided to BPA by wholesale power market sales are qualitatively superior in several respects to the reserves previously provided to BPA by the DSIs. For example, the DSI reserves provided recall or interruption rights only for specified portions of the power sales to the DSIs and only for specified purposes and durations.

In past BPA rate proceedings when BPA had significant DSI loads, BPA calculated reserve benefits by escalating the 1987 value of reserve benefits, which was determined by using BPA's traditional method of valuing DSI reserve benefits.

We escalated this 1987 value of reserve benefits to the Test Period, which resulted in average projected reserve benefits of $154 million per year over the Test Period (as compared to projected reserve benefits of $576 million under the method discussed above that we recommend).

Q. **Have you analyzed the effect of correcting the Initial Proposal by adding these reserve benefits developed using the method you recommend to the projected costs in the 7(b)(2) Case?**

A. Yes. Correcting this error alone using our recommended method would reduce the PF Exchange rate by 30.1 mills/kWh, from the 69.6 mills/kWh PF Exchange rate in the Initial Proposal to 39.5 mills/kWh. Reducing the PF Exchange rate by 30.1 mills/kWh by making this correction in the section 7(b)(2) rate step and applying this reduced PF Exchange rate to the residential and small-farm loads and average system costs projected by BPA in this proceeding would increase projected average residential exchange benefits to $365.6 million per year, of which $297.3 million per year would be for residential and small-farm customers of the investor-owned utilities.

Q. **If BPA projects no power sales to the DSIs, should the section 7(b)(2) rate step produce a "trigger amount" that offsets the residential exchange program benefits projected in the Program Case?**

A. No. As demonstrated by this testimony, the section 7(b)(2) rate step should not produce any "trigger amount."

The section 7(b)(2) rate step performed by BPA in the Initial Proposal projects no BPA sales to DSIs, a projection our testimony accepts and does not change. The section 7(b)(2) rate step, as corrected and described in our testimony, results in a zero trigger amount and projected average residential exchange program benefits of $443.4 million per year over the period FY2007-09. *This level of benefits is projected* *under a properly performed section 7(b)(2) rate step even with no BPA sales to the DSIs.*

Section 5. Costs of Uncontrollable Events

Q. Please summarize your testimony regarding BPA's exclusion of amounts charged under section 7(g) for the costs of uncontrollable events in performing the section 7(b)(2) rate step.

A. In performing the section 7(b)(2) rate step, BPA failed to subtract, from the projected amounts to be charged public bodies, cooperatives and federal agency customers in the Program Case, the amounts charged such customers for BPA's costs of uncontrollable events.

BPA failed to subtract from such projected amounts to be charged *any* costs of uncontrollable events. (*See* BPA Response to PS-BPA-015.) Remarkably, BPA has *never* excluded any costs of uncontrollable events in its section 7(b)(2) rate step in any of its rate cases after July 1, 1985, when the rate step became applicable.

Q. What is your understanding of the costs of uncontrollable events to be subtracted in the section 7(b)(2) rate step from the projected amounts to be charged public bodies, cooperatives and federal agency customers in the Program Case?

A. Section 7(b)(2) of the Northwest Power Act states that

> [a]fter July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) of this section for the costs of . . . uncontrollable events, may not exceed in total, as determined by the Administrator, during [the test period], an amount equal to the power costs for general

> requirements of such customer if, the Administrator [makes the five assumptions specified in section 7(b)(2).]

16 U.S.C. § 839e(b)(2).

Q. In its section 7(b)(2) rate step analysis, does the Initial Proposal subtract any section 7(g) costs from the Program Case?

A. Yes. As in previous cases, the Initial Proposal subtracts some of the conservation costs that should be subtracted from the Program Case. The Initial Proposal states as follows:

> The 7(g) costs quantified for BPA's final rate proposal rate test are comprised of BPA's acquired and projected conservation and billing credits, energy efficiency costs, and C&RD costs.

(WP-07-E-BPA-06, p. 13, ll. 21-23.) Some costs of conservation are subtracted from the Program Case, but no costs of uncontrollable events are subtracted. Further, as discussed elsewhere in our testimony, not all costs of conservation that should have been subtracted were in fact subtracted by BPA.

Q. Are there any costs in the Initial Proposal that are costs of uncontrollable events but are not treated as such in the section 7(b)(2) rate step by subtracting them from the projected amounts to be charged in the Program Case?

A. Yes, the Initial Proposal includes at least the following three categories of costs that are costs of uncontrollable events but are not treated as such in the section 7(b)(2) rate step by subtracting them from the projected amounts to be charged in the Program Case: (a) BPA's costs associated with two terminated nuclear plants, (b) BPA's costs of Financial Reserves for Risk and (c) BPA's costs of Planned Net Revenue for Risk.

a. Costs of Terminated WNP-1 and WNP-3

Q. Please summarize your testimony regarding BPA's failing to subtract, as section 7(g) costs of uncontrollable events, BPA's costs of the terminated WNP-1 and WNP-3.

A. BPA makes the error of failing to subtract from the Program Case, as section 7(g) costs of uncontrollable events, BPA's costs of the terminated WNP-1 and WNP-3. The fact that BPA made a measured, rational response to an uncontrollable event does not and cannot render such event controllable.

BPA's costs of the terminated WNP-1 and WNP-3 are costs of uncontrollable events that should be subtracted as section 7(g) costs in the section 7(b)(2) rate step from the projected amounts to be charged public bodies, cooperatives and federal agency customers in the Program Case.

Correcting this error alone reduces the PF Exchange rate by 25.8 mills/kWh.

Q. Please describe these BPA costs of the terminated WNP-1 and WNP-3.

A. BPA includes average annual costs during the Test Period of $345 million for terminated WNP-1 and WNP-3 in the projected amounts to be charged public bodies, cooperatives and Federal agency customers in the Program Case. (WP-07-E-BPA-06A, pp. 10-16, ll. 6, 8.)

Q. Please generally describe BPA's role with respect to the nuclear projects to be constructed by the Washington Public Power Supply System (the "Supply System").

A. BPA agreed to purchase the output of, and pay the cost of, WNP-1, WNP-2 and 70 percent of WNP-3 under net billing agreements. These three projects were nuclear plants owned and to be constructed and operated by the Supply System. The Supply System was also to construct and own two other nuclear plants (WNP-4 and WNP-5), but BPA did not agree to purchase the output from, or to pay the costs of, such projects.

In January 1982, the Supply System terminated WNP-4 and WNP-5. In July 1983, the Supply System announced the largest municipal bond default in history when it was unable to repay the principal and interest on $2.25 billion of bonds sold to finance construction of WNP-4 and WNP-5.

Q. Why are BPA's costs of terminated WNP-1 and WNP-3 the costs of uncontrollable events?

A. The Supply System was unable to issue bonds to finance completion of WNP-1 and WNP-3, and they were subsequently terminated without being completed or producing power. The Supply System's inability to issue bonds was an uncontrollable event. BPA's costs with respect to WNP-1 and WNP-3, from which BPA received no power, are costs of "uncontrollable events."

Q. Has BPA previously recognized that the costs of terminated generating facilities, such as WNP-1 and WNP-3, are the costs of uncontrollable events for purposes of section 7(g) of the Northwest Power Act?

A. Yes. The initial long-term power sales contracts under the Northwest Power Act entered into by BPA with utilities in the region recognized that BPA's costs of uncontrollable events to be allocated under section 7(g) of the Northwest Power Act include costs of a "terminated generating facility":

> Allocation of Certain Section 7(g) Costs. *Costs of uncontrollable events, including but not limited to costs of a terminated generating facility*, and costs of experimental resources, in excess of the cost of cost-effective resources, shall be allocated pursuant to section 7(g) of P.L. 96-501 [the Northwest Power Act] and shall be allocated among Customers on a uniform per kilowatt or kilowatthour basis.

(Emphasis added.) Exhibit WP-07-E-JP6-06 submitted herewith is a copy of this contract provision. Thus, when BPA was first implementing the Northwest Power Act, it recognized and defined costs of terminated generating facilities as costs attributable to uncontrollable events. This recognition is not erased or negated by the expiration of those contracts in 2001. BPA's failure to exclude its costs of WNP-1 and WNP-3 is inconsistent with BPA's earlier and long-standing interpretation of the Northwest Power Act.

Q. Have you analyzed the effect of correcting the error you describe above regarding BPA's failure to include its costs of terminated WNP-1 and WNP-3 (as costs of uncontrollable events) in the costs to be subtracted as section 7(g) costs from the Program Case in performing the section 7(b)(2) rate step?

A. Yes. Correcting this error alone would reduce the PF Exchange rate by 25.8 mills/kWh, from the 69.6 mills/kWh PF Exchange rate in the Initial Proposal to 43.8 mills/kWh. Reducing the PF Exchange rate by 25.8 mills/kWh by making this correction in the section 7(b)(2) rate step and applying this reduced PF Exchange rate to the residential and small-farm loads and average system costs projected by BPA in this proceeding would increase projected average residential exchange benefits to $145.5 million per year, of which $110.6 million per year would be for residential and small-farm customers of the investor-owned utilities. (This correction was made using BPA's method for allocating the specified section 7(g) costs that are to be subtracted from the Program Case in the performance of the section 7(b)(2) rate step. As we discuss below, this BPA allocation method is also erroneous, and the effects of correcting this allocation error are discussed below.)

b. Costs of Financial Reserves for Risk

Q. Please summarize your testimony regarding BPA's failing to subtract, as section 7(g) costs of uncontrollable events, any of the Financial Reserves for Risk held by BPA as risk mitigation funds.

A. BPA makes the error of failing to subtract from the Program Case, as section 7(g) costs of uncontrollable events, any of the Financial Reserves for Risk held by BPA as risk mitigation funds to mitigate the impacts of operating and non-operating risks.

Correcting this error alone reduces the PF Exchange rate by up to 17.0 mills/kWh.

Q. Please describe BPA's Financial Reserves for Risk.

A. Financial reserves in excess of required working capital ("Financial Reserves for Risk") are reserves carried by BPA to mitigate the impacts of operating and non-operating risks:

> Traditionally, BPA has relied on its cash reserves and the addition of Planned Net Revenues for Risk (PNRR) to its revenue requirement as the primary risk mitigation tools in setting rates.

(WP-07-E-BPA-08, p. 7, ll. 23-25.) Financial reserves provide the "fundamental protection against the financial impacts of the risks BPA faces is its financial reserves." (WP-07-E-BPA-04, p. 39, ll. 25-26.)

BPA projects $381 million of financial reserves as of the beginning of the rate period. (WP-07-E-BPA-04, p. 82, table 5.) BPA also projects that, during the rate period, it will require $50 million of working capital:

> We assume no change to the $50 million level of liquidity reserves (or "working capital") assumed in meeting the Treasury Payment Probability in the 1993 and 1996 rate proposals and the 2002 rate proposal.

(WP-07-E-BPA-08, p. 9, ll. 7-9.) Thus, as of the beginning of the rate period, BPA projects Financial Reserves for Risk of $331 million (the difference between $381 million and $50 million). In the absence of the risk of uncontrollable events that give rise to the need for Financial Reserves for Risk, BPA's revenue requirement during the rate period would be $331 million lower, allowing BPA to lower rates in this proceeding so as to collect approximately $110 million per year ($331 million over three years) less over the rate period.

BPA's failure to lower rates by this amount constitutes a cost in this rate period. BPA's failure to lower rates by this amount and the resulting cost are due to the uncontrollable events for which BPA maintains Financial Reserves for Risk. Hence such costs must be subtracted from the Program Case as section 7(g) costs in performing the section 7(b)(2) rate step.

Q. Have you analyzed the effect of correcting the error you describe above regarding this BPA failure to include Financial Reserves for Risk in the costs to be subtracted from the Program Case as section 7(g) costs in performing the section 7(b)(2) rate step?

A. Yes. Correcting this error alone would reduce the PF Exchange rate by up to 17.0 mills/kWh, from the 69.6 mills/kWh PF Exchange rate in the Initial Proposal to 52.6 mills/kWh. Reducing the PF Exchange rate by 17.0 mills/kWh by making this correction in the section 7(b)(2) rate step and applying this reduced PF Exchange rate to the residential and small-farm loads and average system costs projected by BPA in this proceeding would increase projected average residential exchange benefits to $37.8 million per year, of which $32.7 million per year would be for residential and small-farm customers of the investor-owned utilities. (This correction was made using BPA's method for allocating the specified section 7(g) costs that are to be subtracted from the Program Case in the performance of the section 7(b)(2) rate step. As we discuss below, this BPA allocation method is also erroneous, and the effects of correcting this allocation error are discussed below.)

c. Costs of PNRR

Q. Please summarize your testimony regarding BPA's failing to subtract, as section 7(g) costs of uncontrollable events, the PNRR included by BPA in the amounts charged under its Initial Proposal.

A. BPA makes the error of failing to subtract from the Program Case, as section 7(g) costs of uncontrollable events, the PNRR included by BPA in the amounts charged under its Initial Proposal.

Correcting this error alone reduces the PF Exchange rate by up to 15.5 mills/kWh.

Q. **Please describe BPA's Planned Net Revenue for Risk ("PNRR").**

A. As discussed above, the addition of PNRR to BPA's revenue requirement is a primary risk mitigation tool in setting BPA rates. (*See* WP-07-E-BPA-08, p. 7, ll. 23-25.) BPA describes PNRR as the "backstop" in its risk mitigation portfolio:

> PNRR as a way to increase reserves is the backstop in BPA's risk mitigation portfolio: whatever risk is not mitigated by other tools and projected reserves will be mitigated by increases in reserves generated by PNRR.

(WP-07-E-BPA-14, p. 7, ll. 7-9.) In other words, BPA's costs to be recovered in BPA's rates in this proceeding are higher by the amount of PNRR. Costs of PNRR are the costs of uncontrollable events.

Q. **How much PNRR has BPA added in its Initial Proposal?**

A. For the Initial Proposal, BPA added $101 million per year of PNRR costs. (WP-07-E-BPA-04, p. 82, table 5.)

Q. **Have you analyzed the effect of correcting the error you describe above regarding BPA's failure to include PNRR in the costs to be subtracted from the Program Case as section 7(g) costs in performing the section 7(b)(2) rate step?**

A. Yes. Correcting this error alone would reduce the PF Exchange rate by 15.5 mills/kWh, from the 69.6 mills/kWh PF Exchange rate in the Initial Proposal to 54.1 mills/kWh.

Reducing the PF Exchange rate by 15.5 mills/kWh by making this correction in the section 7(b)(2) rate step and applying this reduced PF Exchange rate to the residential and small-farm loads and average system costs projected by BPA in this proceeding would increase projected average residential exchange benefits to $32.3 million per year, of which $28.1 million per year would be for residential and small-farm customers of the investor-owned utilities.

Q. Have you analyzed the combined effect of correcting the errors you describe above regarding BPA's failure to include (as costs of uncontrollable events) (i) its costs of terminated WNP-1 and WNP-3, (ii) its costs of Financial Reserves for Risk and (iii) its costs of PNRR in the costs to be subtracted from the Program Case as section 7(g) costs in performing the section 7(b)(2) rate step?

A. Yes. Correcting these errors alone would reduce the PF Exchange rate by 27.0 mills/kWh, from the 69.6 mills/kWh PF Exchange rate in the Initial Proposal to 42.6 mills/kWh. Reducing the PF Exchange rate by 27.0 mills/kWh by making these corrections in the section 7(b)(2) rate step and applying this reduced PF Exchange rate to the residential and small-farm loads and average system costs projected by BPA in this proceeding would increase projected average residential exchange benefits to $199.5 million per year, of which $155.4 million per year would be for residential and small-farm customers of the investor-owned utilities. (These corrections were made using BPA's method for allocating the specified section 7(g) costs that are to be subtracted from the Program Case in the performance of the section 7(b)(2) rate step. As we discuss below, this allocation method is also erroneous, and the effects of correcting this allocation error are discussed below.)

d. BPA's WP-02 Record of Decision Issued in 2000

Q. Did BPA discuss the costs of uncontrollable events due to the terminated WNP-1 and WNP-3, Financial Reserves for Risk and PNRR in the WP-02 rate proceeding?

A. The Administrator's Record of Decision issued in 2000 in the WP-02 rate proceeding (the "WP-02 ROD") discussed the costs of uncontrollable events due to the terminated WNP-1 and WNP-3 and PNRR, but did not discuss the costs of Financial Reserves for Risk.

In the WP-02 ROD, BPA took the erroneous position that "uncontrollable events is a statutory term that logically refers to discrete events which differ from the continuum of changing events that occur in nature, business, and government and are routinely reflected in ratemaking." (WP-02-A-02, pp. 13-41.) However, there is nothing in the Northwest Power Act of which we are aware that excludes events from being uncontrollable events simply because they might be characterized in a "continuum of changing events that occur in nature, business, and government and are routinely reflected in ratemaking."

In the WP-02 ROD, BPA took the position that "the shutdown of several plants in Washington [WNP-1 and WNP-3] was a planned controlled event that was part of a deliberative process which is characterized by or results from consideration of relevant factors." (WP-02-A-02, pp. 13-44.) This conclusion in no way demonstrates that the shutdown was not due to uncontrollable events.

The fact that BPA engaged in a deliberative process regarding how to address these uncontrollable events (and, presumably, mitigate some of the total costs) once they occurred does not change the fact that the costs were the result of uncontrollable events. Presumably, BPA would engage in that same deliberative process following damage to a generating facility caused by an earthquake, flood or terrorist act, to determine whether to terminate or try to repair or replace the facility and plan a course of action for implementing such decisions.

Costs of uncontrollable events cannot be transformed into costs of controllable events merely by their inclusion in BPA's revenue requirement, whether such inclusion is routine or otherwise. For example, the fact that BPA routinely recovers the costs of the uncontrollable events that caused the termination of WNP-1 and WNP-3 in its rates does not and cannot force the conclusion that such costs were not the costs of uncontrollable events.

Similarly, the fact that BPA routinely includes PNRR in its revenue requirements to cover the costs of uncontrollable events does not and cannot force the conclusion that such events are not "uncontrollable events" and that such costs are not the costs of "uncontrollable events."

Section 6. Allocation of Specified Amounts Charged Under Section 7(g)

Q. Please summarize your testimony regarding BPA's allocation of amounts charged under section 7(g) in performing the section 7(b)(2) rate step.

A. BPA makes the error of failing to subtract from the Program Case the proper amount of conservation and other specified section 7(g) costs because BPA has failed to properly allocate such costs.

The cumulative effect of correctly allocating the specified section 7(g) costs, including the corrected amounts for costs of uncontrollable events as described in this testimony, reduces the PF Exchange rate by up to 30.1 mills/kWh.

Q. What is your understanding of the specified section 7(g) costs that are to be subtracted in the section 7(b)(2) rate step from the projected amounts to be charged public bodies, cooperatives and federal agency customers in the Program Case?

A. Section 7(b)(2) of the Northwest Power Act states:

> After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) of this section for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during [the test period], an amount equal to the power costs for general requirements of such customer if, the Administrator [makes the five assumptions specified in section 7(b)(2).]

16 U.S.C. § 839e(b)(2).

Q. Please summarize BPA's allocation of specified amounts charged under section 7(g) in performing the section 7(b)(2) rate step.

A. As discussed above in Section 5, BPA erroneously *determined* the section 7(g) costs with respect to uncontrollable events in performing the section 7(b)(2) rate step. In addition, BPA erroneously *allocated* the specified section 7(g) costs to be subtracted from the Program Case. It is this erroneous allocation that is addressed in this section of our testimony.

BPA erroneously allocated the specified section 7(g) costs such as conservation costs that are to be subtracted from the Program Case in the performance of the section 7(b)(2) rate step. BPA failed to subtract, from the projected amounts to be charged public bodies, cooperatives and federal agency customers in the Program Case, the full amount of specified section 7(g) costs that should be assumed to be allocated to such customers in such rate step. Instead, BPA assumed that some of such section 7(g) costs were allocated to PF Exchange loads that were projected not to exist as a result of such section 7(b)(2) rate step.

Specifically, BPA allocated the specified section 7(g) costs across the sum of (i) projected PF loads plus (ii) PF Exchange loads that the Initial Proposal's section 7(b)(2) rate step itself projected would not occur. The section 7(b)(2) rate step in the Initial Proposal allocated, for example, some $200 million of average annual conservation costs across 6,917 aMW of projected PF loads plus 6,206 aMW of PF Exchange loads that the Initial Proposal's section 7(b)(2) rate step itself projected would not occur:

$$\frac{\$200 \text{ million}}{(6{,}917 \text{ aMW} + 6{,}206 \text{ aMW})} = 1.74 \text{ mills/kWh}$$

In fact, the Initial Proposal should have allocated the $200 million of annual average conservation section 7(g) costs across the loads of 6,917 aMW projected by the section 7(b)(2) rate step itself:

$$\frac{\$200 \text{ million}}{(6{,}917 \text{ aMW} + 0 \text{ aMW})} = 3.30 \text{ mills/kWh}$$

In this example, the Initial Proposal should have subtracted the $200 million of average annual section 7(g) conservation costs, but subtracted only $105 million of such costs:

1.74 mills/kWh * 6,917 aMW = $105 million

Thus, in this example, $95 million of average annual section 7(g) conservation costs that should have been subtracted from the Program Case have, instead, apparently vanished. As a result, BPA has overstated the section 7(b)(2) trigger amount. Similarly, the $556 million of costs of uncontrollable events discussed above should have been allocated in the section 7(b)(2) rate step across the loads that such rate step itself projects. In short, *all specified section 7(g) costs* should be allocated in the section 7(b)(2) rate step across the loads that such rate step itself projects.

Q. Have you analyzed the effect of correcting the errors you describe above regarding allocation of specified section 7(g) amounts in performing the section 7(b)(2) rate step?

A. Yes. The cumulative effect of correctly allocating the specified section 7(g) costs, including the corrected amounts for costs of uncontrollable events described in Section 5 of this testimony would reduce the PF Exchange rate by up to 30.1 mills/kWh, from the 69.6 mills/kWh PF Exchange rate in the Initial Proposal to 39.5 mills/kWh. Reducing the PF Exchange rate by 30.1 mills/kWh by making these corrections in the section 7(b)(2) rate step and applying this reduced PF Exchange rate to the residential and small-farm loads and average system costs projected by BPA in this proceeding would increase projected average residential exchange benefits to $365.6 million per year, of which

$297.3 million per year would be for residential and small-farm customers of the investor-owned utilities.

III. THE 1984 ASC METHODOLOGY—EXCLUSION OF INCOME TAXES AND RETURN ON EQUITY FROM AVERAGE SYSTEM COSTS

Q. Please summarize your testimony regarding the 1984 ASC Methodology's exclusion of income taxes and return on equity from average system costs.

A. The 1984 ASC Methodology should be revised to include income taxes and return on equity in the determination of the average system cost of each investor-owned utility. The 1984 ASC Methodology's exclusion of income tax and return on equity was upheld by the Ninth Circuit only as a temporary measure.

Q. Should BPA exclude taxes and return on equity in calculating each utility's Average System Cost ("ASC")?

A. No. BPA used the 1984 ASC Methodology to develop individual utility base ASC. (WP-07-E-BPA-16, p. 11; *see also* WP-07-E-BPA-05, pp. 54-68.)

In *PacifiCorp v. FERC* ("*PacifiCorp*"), the Ninth Circuit reviewed a decision in which the BPA Administrator in 1984 elected to revise the initial ASC Methodology as negotiated with exchanging utilities in 1981 (the "1981 ASC Methodology"). 795 F.2d 816 (9th Cir. 1986) The new ASC Methodology (the "1984 ASC Methodology") sharply reduced residential exchange program benefits received by the residential and small-farm customers of the investor-owned utilities under residential purchase and sale agreements by removing the costs of income taxes and return on equity from the ASC calculation. As explained by the court:

> The revised methodology had the effect of reducing the average system cost in two material ways. First, it eliminated income taxes from average system cost calculations, and second, it eliminated return on equity as a cost factor and substituted for it the embedded cost of long-term debt. The result is a substantial reduction in the amount of money which BPA pays to the IOUs under the exchange program.

Id. at 819. This election to reduce residential exchange program benefits was challenged in a series of lawsuits by investor-owned utilities and by state regulatory agencies, leading to the decision in *PacifiCorp*.

In *PacifiCorp*, the court upheld BPA's discretion as exercised in the 1984 ASC Methodology to exclude certain costs from its ASC calculation, based on then existing facts presented to the court. Specifically, the court relied on BPA's determination that certain terminated generation plant costs, which could not by statute be included in ASC, were being indirectly recovered through an increase in equity returns allowed to a utility. However, the court's decision emphasized its reliance on these special facts and noted that it was not sanctioning a continuation of the exclusions once the need for them had passed:

> In upholding BPA's ASC determinations in this case, however, we do not sanction any permanent implementation of these exclusions. We uphold the exclusions in this instance because we conclude that we must defer to BPA's view that the statute authorizes such adjustments in ASC in response to BPA's experience with the program and the need to avoid abuses. The record in this case reflects that this is such a situation. The statute itself, however, neither commands nor proscribes these adjustments in ASC methodology.

Id. at 823. The 1984 ASC Methodology should be revised to include income taxes and return on equity in the determination of the ASC of each investor-owned utility.

IV. CONCLUSION

Q. Do you have any recommendations regarding how BPA should approach correction of the errors in the Initial Proposal described in your testimony?

A. Yes. As discussed above, BPA has erroneously performed the section 7(b)(2) rate step and erroneously failed to include income taxes and return on equity in the ASC of each investor-owned utility. Each of the errors in the section 7(b)(2) rate step described in our testimony should be corrected in this proceeding. The 1984 ASC Methodology should be corrected in a separate proceeding as discussed below.

The Pacific Northwest Investor-Owned Utilities will not be participating in residential exchange purchase and sale agreements for the duration of their respective residential exchange program settlement agreements with BPA. However, the types of BPA errors discussed in our testimony must be addressed at some point, and even now it is clear that they must be addressed for BPA rate periods beginning October 2011. BPA certainly should revise the BPA Legal Interpretation and the 1984 ASC Methodology to reflect the recommendations in our testimony, and such revisions should be in place well before the end of the existing residential exchange program settlement agreements with BPA.

Q. Can BPA revise the BPA Legal Interpretation and the 1984 ASC Methodology?

A. Yes, the BPA Legal Interpretation and the 1984 ASC Methodology may be revised consistent with the Northwest Power Act. In the BPA Legal Interpretation, BPA concluded that section 7(b)(2)

> is a clear grant of discretion to the Administrator to determine the manner in which the five assumptions of section 7(b)(2) are applied and the rate

> test is implemented. However, BPA recognizes that the reasonableness and methodologies used to implement section 7(b)(2) will be tested in the relevant rate [cases].

BPA Legal Interpretation at 24,000.

Q. What process should BPA use to revise the 1984 ASC Methodology?

A. Section 5(c)(7) of the Northwest Power Act states that ASCs shall be determined

> on the basis of a methodology developed for this purpose in consultation with the Council, the Administrator's customers, and appropriate State regulatory bodies in the region. Such methodology shall be subject to review and approval by the Federal Energy Regulatory Commission.

16 U.S.C. § 839c(c)(7). A separate proceeding is necessary to revise the 1984 ASC Methodology, and BPA should commence this process without delay.

Q. Does this conclude your testimony?

A. Yes.