UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
BEFORE THE
BONNEVILLE POWER ADMINISTRATION

Fiscal Year 2012-2013 Proposed Power Rate Adjustments Public Hearing and Opportunities for Public Review and Comment	**))))**	**BPA Docket No. BP-12**

***ATTACHMENTS* TO DIRECT TESTIMONY OF:**

PUBLIC POWER COUNCIL,

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES,

NORTHWEST REQUIREMENTS UTILITIES, AND

PACIFIC NORTHWEST GENERATING COOPERATIVE (for both itself and the PNGC Members)

<u>SUBJECT:</u>

DSI SERVICE ASSUMPTIONS AND RATES

WITNESSES:
Michael Deen
Kevin O'Meara
Lincoln Wolverton
Geoffrey Carr
Douglas Brawley

January 20, 2011

ATTACHMENT 1

The Following DATA RESPONSE Has Been Issued:

DATA REQUEST NUMBER TO REFERENCE:
NR-BPA-1

RESPONSE BY:
Diane Cherry - Bonneville Power Administration

ORIGINAL DATA REQUEST:
Please provide an estimate of the cost to the Slice and Non-Slice customers of serving 340 aMW of DSI load in FY 2012 and 2013.

EXHIBIT: Testimony on Power Rates Policy; Witnesses: Raymond D. Bliven, Mary A. Hawken, Diane Cherry BP-12-E-BPA-11

PAGE(S): 19
LINE(S): 5-6

DATA RESPONSE: (NOTE: You MUST log in to the site in order to view any documents)

--TEXT DESCRIPTION:

Pursuant to Section 1010.8(b) of the Rules of Procedure Governing BPA Rate Hearings, "no party shall be required to perform any new study or to run any analysis or computer program."

The version of the RAM2012 model made available to the parties is not capable of performing the requested analysis. However, an estimate of the cost to the Slice and Non-Slice customers of serving 340 aMW of DSI load in FY 2012 and 2013 can be calculated using the cost and revenue values available in the Power Rates Study Documentation, BP-12-E-BPA-01A.

Assuming no system sales to the DSIs, BPA's forecast of system augmentation would be about 350 aMW lower (340 aMW sale plus 0.0282% for transmission losses). Table 2.5.2, row 14 shows the value of augmentation for FY 2012-FY 2013 to be $41.81 and $47.13 respectively, yielding an annual cost of about $136.6 million per year. Table 2.5.7.3. row 52 shows a two-year IP rate revenue of $217.5 million, or $108.8 million per year. The difference of the cost and revenue is $27.8 million per year, or $55.6 million over the two-year rate period. Table 2.5.6.2, row 22 shows the TRM PF revenues of $3,779.3 million over the two-year rate period. Therefore, the estimated cost of serving the DSIs is about 1.5% on the TRM PF revenues.

For technical questions about this response, please contact Bill Doubleday by phone [503-230-7570 and/or wjdoubleday@bpa.gov. For other questions about this response please contact Peter Burger by phone 503-230-4148 and/or email pjburger@bpa.gov.

ATTACHMENT 2

ADMINISTRATOR'S RECORD OF DECISION GRANTING ALCOA'S REQUEST TO EXTEND THE INITIAL PERIOD OF ALCOA'S POWER SALES AGREEMENT, CONTRACT NO. 10PB-12175

October 29, 2010

BONNEVILLE
POWER ADMINISTRATION

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ADMINISTRATOR'S RECORD OF DECISION
GRANTING ALCOA'S REQUEST TO EXTEND THE INITIAL PERIOD OF ALCOA'S POWER SALES AGREEMENT, CONTRACT NO. 10PB-12175

October 29, 2010

I. INTRODUCTION

On December 21, 2009, the Administrator signed a block power sales contract (the "Block Contract") with Alcoa Inc. ("Alcoa"). Under the Block Contract, BPA is selling up to 320 aMW of firm power to Alcoa at the Industrial Firm (IP) power rate over approximately 17 months. Power deliveries began on December 22, 2009, and are scheduled to end May 26, 2011 (the "Initial Period"). Prior to the execution of the Block Contract, BPA provided the draft contract for public comment. BPA's record of decision (the "Alcoa ROD") dated December 22, 2009, addressed the comments received and provided the rationale supporting BPA's decision to enter into the Block Contract, in light of the comments received and the opinions of the United States Court of Appeals for the Ninth Circuit ("Court" or "Ninth Circuit") in *Pacific Northwest Generating Coop. v. Dep't of Energy*, 580 F.3d 792 (9th Cir. 2009) ("*PNGC I*") and *Pacific Northwest Generating Coop. v. BPA*, 580 F.3d 828 (9th Cir. 2009) ("*PNGC II*"). The Block Contract is currently being challenged in the Ninth Circuit. [1]

Section 5.1 of the Block Contract provides that BPA will evaluate extending such firm sale for one additional period of 3 to 12 months (the "Extended Initial Period") upon written request by Alcoa.[2] Alcoa submitted its request to BPA for an extension up to 12 months on September 2, 2010.[3] This record of decision documents BPA's final determination to grant Alcoa's request based on the evaluation of Equivalent Benefits for the Extended Initial Period

Prior to making its final determination whether or not to extend the contract, BPA provided an opportunity for public review and comment regarding its draft evaluation of the Equivalent Benefits Test (the "EBT") for the Extended Initial Period. The public

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[1] On January 22, 2010, Alcoa filed suit in the United States Court of Appeals for the Ninth Circuit contesting the Block Contract.

[2] The Block Contract also provides for power sales to Alcoa for up to an additional 12-month (Transition Period) and an additional 5 years (Second Period) if certain specified conditions, applying appropriately to each period, are met. *See* Alcoa ROD at 18-19.

[3] Letter from Mike Rousseau, Plant Manager, Alcoa, to Mark E. Miller, Account Executive, Bonneville Power Administration (Sept. 2, 2010). *See* Attachment A

review and comment period took place from October 6, 2010, through October 21, 2010. In its request for public comments, BPA stated that the scope of review is limited to the draft determination and that issues or comments pertaining to why BPA entered into the Block Contract, BPA's legal authority, or any other related threshold matters are not within the scope of this determination. *See supra*, section II, for further discussion of the scope of this determination. BPA agrees that issues raised in the pending litigation of the Block Contract, and arguments and responses thereto, are not waived by virtue of not being raised during the comment period for this Equivalent Benefits determination.

Canby, EBT100005, at 1, asks if the decision to provide service for an Extended Initial Period is a new final decision, or if it was encompassed in BPA's final agency action when it signed the contract in 2009. In response, BPA observes that section 9(e)(1) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839 et seq. (the "Northwest Power Act" or the "Act") lists sales of power under section 5 of the Act as a final action subject to judicial review. In practice, this means BPA's contracts for the sale of power, since it is the contract that provides for the sale. Here, Alcoa's current contract is the subject of judicial review and there is no new contract of sale. However, section 9(e)(5) of the Northwest Power Act provides for exclusive Ninth Circuit review not only of "final actions and decisions taken pursuant to this Act" but also "the implementation of such final actions." 16 U.S.C. § 839f(e)(5). Here, as described in section II below, BPA is implementing section 5.1 of the Block Contract. While BPA believes its determination of the EBT would be subject to review under section 9(e)(5) as a final action, particularly since the matter is an administrative determination, we would anticipate that some customers would argue that implementation of a contract is a matter purely of whether BPA has done what its contract requires and should be treated as such.

II. SCOPE OF DETERMINATION

As established in the Alcoa ROD, the EBT is intended to demonstrate that a decision to serve a DSI customer is, as described by the Court, consistent with sound business principles when it can be shown that the benefits to BPA of serving the DSI load would equal or exceed BPA's cost of serving the load during the period of service ("Equivalent Benefits").[4] Comments submitted that pertain to why BPA entered into the Block Contract, legal authority, BPA's reading of *PNGC II*, or any other related threshold matters, many of which were addressed in the Alcoa ROD and are pending review in current litigation, are not within the scope of this determination and are therefore not addressed here.

As indicated in BPA's October 6, 2010, request for public comments, section 5.1 of BPA's power sales contract with Alcoa provides that "[u]pon written request by Alcoa, BPA will evaluate extending the Initial Period by no less than three months and no more than one year ("Extended Initial Period"), and will so extend the Initial Period for the duration requested by Alcoa if BPA determines that it will achieve Equivalent Benefits

[4] *See* Alcoa ROD, December 22, 2009, at 8-9.

from such Firm Power sales during such Extended Initial Period." Consequently, BPA's final decision in executing the contract encompassed section 5.1, among all the other contract terms. Inasmuch as section 5.1 provides that BPA will extend the Initial Period if it determines it will achieve Equivalent Benefits from such Firm Power sales during such Extended Initial Period, the only determination at issue here is whether Equivalent Benefits exist to justify an Extended Initial Period. For that reason, BPA limited comments in this comment forum to that determination.

BPA's position is not inconsistent with PNGC's observation that BPA has stated in its briefing to the Ninth Circuit on the Block Contract that "[t]he EBT [Equivalent Benefits Test] is a tool developed by BPA to determine *whether* service to a DSI would be consistent with sound business principles, as required by *PNGC II*." PNGC, EBT100011, at 2. PNGC also wonders how addressing the application of BPA's EBT "to the proposed contract extension" can exclude a discussion of whether BPA's actions are consistent with statutory mandates and the Ninth Circuit decisions. BPA's answer is that, as indicated, BPA's earlier final action in executing the Block Contract encompassed all of its terms, including that BPA would provide service for an Extended Initial Period if BPA determined it will achieve Equivalent Benefits for such period. BPA believes the EBT satisfies sound business principles and other legal requirements, all as stated in its earlier ROD, *see generally* Alcoa ROD, and that it in fact may demand too much, as set forth in BPA's brief to the Ninth Circuit in the currently pending case involving review of the Block Contract. Therefore, in executing the Block Contract, BPA already made its determination that the law would be satisfied by applying the EBT to determine whether an Extended Initial Period is justified. The only new determination at issue here is BPA's conduct of the EBT, and BPA will confine its responses here to comments on that determination.

As a consequence of the foregoing, BPA will not here visit or re-visit comments:

- by Alcoa (EBT100006) concerning the legitimacy of the EBT, indirect benefits of serving DSI loads, or other matters not directly bearing on BPA's conduct of the EBT;
- by Pacific Northwest Generating Cooperative (PNGC) (EBT100011) concerning matters other than BPA's conduct of the EBT, including comments on BPA's prior final decision, water conditions for the Initial Period, legal obligations, and pricing based on cost causation;
- by Industrial Customers of Northwest Utilities (ICNU) (EBT100008) concerning legality of DSI service and service obligations to other customers;
- by Public Power Council (PPC) (EBT100001) concerning overall policy context; and
- concerning general economic conditions and the need to preserve jobs, whether DSI jobs (EBT100002, EBT100004) or other jobs in other areas (Sanger/ICNU, EBT100008).

Additionally, BPA is of the opinion that issues related to implementation of sections of the Block Contract that do not pertain to the EBT concerning extension of the Initial

Period are outside the scope of this determination. However, BPA will address the following comment regarding the employment level at Alcoa's Intalco Plant from SUB in order to clarify that BPA believes that the Block Contract is being faithfully performed by Alcoa. SUB, EBT100007 at 8, commented that:

> SUB notes that a comment on this topic from Alcoa indicates 520 workers. Even if this represented 520 FTE (as opposed to full time and part time employees), 520 FTE is not sufficient to meet the criteria in the Alcoa contract [Block Contract] to grant 320 aMW of power. From this perspective, the EBT test for 320 aMW is moot. (Internal citations omitted.)

SUB is correct in that Exhibit G of the Block Contract requires specific employment levels. *See* Block Contract, section 8. This contractual requirement is not related to nor is it a prerequisite of the extension of the Initial Period. However, BPA notes that section 8 of the Block Contract requires that Alcoa shall provide monthly reports to BPA demonstrating its employment levels (full time equivalents, or FTE) by month. Alcoa's September 2010 employment report to BPA, the most recent report made pursuant to section 8, indicates that Alcoa has met its employment obligations under the contract to date by employing a cumulative average of more than 630 FTE, which is approximately 100 FTE above the 528 FTE required. The monthly reports provided by Alcoa pursuant to the Block Contract will be the basis for any action taken under section 8 of the Block Contract.

III. BLOCK CONTRACT – PURCHASE AND SALE OF FIRM POWER FOR THE EXTENDED INITIAL PERIOD

a. Firm Power Amounts

Pursuant to the Block Contract, BPA agreed (subject to certain conditions described below) to make available to Alcoa, and Alcoa agreed to purchase from BPA (on a take-or-pay basis) up to 320 aMW on a take-or-pay basis for, potentially, a period of up to approximately seven years, at the Industrial Firm (IP) power rate.

As of the contract effective date, BPA would have made available 285 aMW to Alcoa, but Alcoa requested that BPA increase such amount to 320 aMW, pursuant to applicable contract provisions. *See* Block Contract section 5.2. As described more fully in the Alcoa ROD, BPA concluded that it will achieve Equivalent Benefits from the sale of 320 aMW to Alcoa during the Initial Period, and granted Alcoa's request.[5] Pursuant to contractual provisions, BPA's EBT determinations are conclusive and binding on Alcoa, and may not be challenged by Alcoa in any forum. *See* Block Contract sections 5.2 and 25.1.

[5] *See* Alcoa ROD, section IV(a), at 10.

b. Term of the Block Contract

The term of the Block Contract is divided into two main periods, the Initial Period and the Second Period, with the Initial Period encompassing the approximately 17 month period from December 22, 2009, through May 26, 2011, and the Second Period encompassing a five-year period following expiration of the Initial Period, Extended Initial Period, and Transition Period (if any). *See* Block Contract, sections 5 and 6. The Block Contract provides that the Initial Period may be extended at the request of Alcoa, subject to BPA's determination of Equivalent Benefits. Alcoa submitted its written request for an extension of the Initial Period to BPA on September 2, 2010, pursuant to section 5.1.1 of the Block Contract. BPA has determined to extend the Initial Period for twelve months based on its finding that it will achieve Equivalent Benefits from the sale of 320 aMW to Alcoa for the twelve months requested by Alcoa. Pursuant to contractual provisions, BPA's determination is conclusive and binding on Alcoa, and may not be challenged by Alcoa in any forum. *See* Block Contract, sections 5.2 and 25.1.

Therefore, the Initial Period, including the extension, will have a term of 29 months, lasting through May 26, 2012. *See* Block Contract, section 5. In response to Canby Utility Board's comments (EBT 100005 at 1), this extension of the Initial Period will not reduce the duration of the Second Period, if any. With the extension, the maximum potential term of the entire Block Contract will be approximately eight years. The extension of the Initial Period was provided for in the Block Contract and does not represent a change to the original maximum potential term of the contract. *See* Block Contract, section 5.

IV. THE EQUIVALENT BENEFITS TEST

A key element of BPA's response to *PNGC II* was to implement an Equivalent Benefits Test to determine whether BPA could make a power sale to a DSI consistent with the Court's opinion. As established in the Alcoa ROD, the EBT is intended to demonstrate that a decision to serve a DSI customer is consistent with sound business principles when it can be shown that the benefits to BPA of serving the DSI load would equal or exceed BPA's cost of serving the load during the period of service. In this evaluation of extending the Initial Period, BPA analysis demonstrates that it can supply firm power to Alcoa as requested and the need to acquire power to serve the Alcoa load during the Extended Initial Period will be limited because BPA anticipates serving the Alcoa load from inventory under most water conditions. BPA followed the steps of the EBT to determine that it can provide service to Alcoa for an Extended Initial Period of 12 months, during which term the forecast benefits of the sale equal or exceed forecast costs.

In its Draft Determination of Equivalent Benefits dated October 6, 2010, BPA included a calculation of cumulative net benefits that occurred prior to the period at issue in this determination, May 27, 2011 to May 26, 2012. Some commenters suggest that BPA's calculation of cumulative net benefits occurring from the Block Contract outside this 12-month period is outside the scope of comment, should not have been introduced by BPA, and should not, in connection with the equivalent benefits determination made here, be relied upon by BPA or argued by it to justify continued application of the EBT. *See, e.g.*, SUB, EBT100007, at 2-8; ICNU,,EBT100008, at 2. As SUB states, "The issue at hand is: does any benefit for the May 2011 – May 2012 period support Alcoa's request for an extension of service for the May 2011 – May 2012 period?" SUB for the same reasons takes issue with BPA's various "Cumulative" references that incorporate data outside the period May 2011 – May 2012. BPA appreciates and agrees with the comments, and will so confine its analysis and arguments. By so agreeing, BPA is not expressing any position whether as a policy or legal matter it is inappropriate to gauge Equivalent Benefits on a cumulative basis. As it is, the Block Contract speaks to whether Equivalent Benefits are shown "during such Extended Initial Period" and BPA will so confine its analysis. As a further consequence of this correction, BPA will not here address questions raised by Canby, EBT100005, at 2, and SUB, EBT10007, at 6, regarding the calculations and other matters pertaining to determination of what Equivalent Benefits were actually realized outside the May 2011 – May 2012 period.

a. BPA expects to be surplus during the Extended Initial Period

BPA does not forecast needing to make purchases specifically to serve Alcoa during the Extended Initial Period under most water conditions. However, as explained below, BPA has forecast the need to make some purchases, including some normal "balancing" purchases in some months, to meet its total load obligations during FY 2010 through FY 2013, particularly under critical (*i.e.*, very poor) water conditions.[6]

Pursuant to BPA's most recent load and resources studies contained in the *2010 Pacific Northwest Loads & Resources Study* (the "2010 White Book"), which forecasts loads and resources for both the Federal system and the region as a whole for the 10-year period Operating Year (OY) 2011-2020, BPA is forecast to have a surplus of approximately 1,160 aMW and 1,542 aMW on an average annual basis under the middle 80 percent of historical water conditions for OY 2011 and OY 2012 respectively.[7] The Extended Initial Period includes just over 2 months in OY 2011 (May 27, 2011, through July 31, 2011) and just under 10 months in OY 2012 (October 1, 2011, through May 26, 2012). *See* 2010 White Book, Table 8 at 39, and Exhibits 11-12 at 104-107. Alcoa's load during the Extended Initial Period represents approximately 20 percent of the forecast surpluses. Moreover, the 2010 White Book reflects a deficit of 501 aMW and a surplus of 113 aMW on an average

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[6] Balancing purchases are market purchases that BPA makes either before or within a particular month in order to balance its forecast load and resource position within that month. Whether BPA makes any balancing purchases, and in what amounts, is dependent, among other things, on updated water flow forecasts which inform the amount of hydroelectric generation that can be expected in the month, and on within-month weather conditions impacting BPA customer load levels.

[7] Operating Year (OY) in the 2010 White Book is the 12-month period August 1 through July 31. For example, OY 2011 is August 1, 2010, through July 31, 2011. The value of 1,160 aMW of surplus for OY 2011 includes a DSI load of 271 aMW based on signed contracts for service to the DSIs (Alcoa and Port Townsend) through May 2011. The corresponding value of 1,542 aMW for OY 2012 includes 0 aMW of DSI load. If the 271 aMW of DSI loads were removed from OY 2011 the surplus in OY 2011 would increase from 1,160 aMW to 1,431 aMW.

annual basis under 1937-Critical Water Conditions in OY 2011 and OY 2012 respectively, and does so assuming no augmentation and a DSI load of 271 aMW.[8]

The EBT is not based on 1937 Critical Water Conditions, but largely on BPA's forecasts of average water in the 2010 White Book (Average of the Middle 80 percent of Water Conditions) and BPA's recent streamflow expectations for FY 2011 and FY 2012 that contribute to forecasts of hydroelectric generation – outputs of HYDSIM from late July and early August of 2010 – that better reflect lingering effects of the past two relatively dry water years. As stated in the Alcoa ROD, "BPA has set a portion of its rates for FY 2010 and FY2011 based on 1937-Critical Water Conditions as evidenced by Tables 2.3.1 and 2.3.2" entitled Loads and Resources – Federal System and "another portion of BPA's rates, notably the Secondary Sales and Purchases, for FY2010 and FY2011 were set based on average water."[9] *See* Alcoa ROD at 34. BPA expects this approach – using critical water for one portion of its rate setting and average water for other portions of its rate setting – to continue in the upcoming BP-12 rate proceeding and beyond. As a result, BPA expects on an annual basis to be surplus under average water conditions, and as such does not anticipate the need to alter its purchasing strategy for the sales that will be made to Alcoa during the Extended Initial Period. This does not preclude the fact that BPA may have to make short term purchases during certain times of the year to balance BPA's loads, including Alcoa, and resources.

b. Benefits to BPA will equal or exceed costs for the Extended Initial Period of the Block Contract.

BPA forecasts that the revenues it will earn from the firm sale of 320 aMW to Alcoa at the IP rate during the Extended Initial Period will exceed the forecast revenues BPA could otherwise obtain from selling that power into the market by approximately $4.8 million. *See* Tables 1-6 below. As a consequence, BPA's finding is that service to Alcoa during the Extended Initial Period satisfies the EBT.

In the same manner described in the Alcoa ROD, BPA's projected monthly revenues are determined by multiplying the heavy load hour (HLH) and light load hour (LLH) energy entitlements and demand entitlement by their respective IP rate components for each month. BPA has calculated revenues under the Block Contract based on a continuing sale of 320 aMW, as outlined in Table 1, of firm power each hour to Alcoa under the IP-10 rate beginning May 27, 2011, and ending May 26, 2012. The energy and demand entitlements are the projected amounts to be sold by diurnal period each month in the Block Contract. Since the Block Contract sells the same number of megawatts in every hour of the month, the demand entitlement is the monthly megawatt amount specified in Table 1. BPA's projected monthly revenues are then accumulated and the result is illustrated in Tables 1 and 2:

[8] 2010 White Book, page 40.

[9] Tables 2.3.1 and 2.3.2 are found in WP-10-FS-BPA-01A at 10-13. Tables 4.6.2, 4.8.1 and 4.8.2 are found in WP-10-FS-BPA-05A at 77, 88-89.

TABLE 1 - Usage and Rates

Month	Alcoa Ferndale Usage			Projected IP Rates			
	Demand (kW)	HLH (MWh)	LLH (MWh)	Demand ($ / kW)	HLH ($ / MWh)	LLH ($ / MWh)	Effective IP Rate ($ / MWh)
May-11	320,000	15,360	23,040	$1.44	$31.69	$22.29	$27.99
Jun-11	320,000	133,120	97,280	$1.32	$31.18	$23.29	$29.68
Jul-11	320,000	128,000	110,080	$1.61	$33.33	$28.66	$33.33
Aug-11	320,000	138,240	99,840	$1.89	$37.31	$31.40	$37.37
Sep-11	320,000	128,000	102,400	$1.96	$36.49	$32.26	$37.33
Oct-11	320,000	133,120	104,960	$2.05	$31.92	$27.01	$32.51
Nov-11	320,000	128,000	102,720	$2.19	$33.33	$29.58	$34.70
Dec-11	320,000	133,120	104,960	$2.30	$35.24	$31.13	$36.52
Jan-12	320,000	128,000	110,080	$1.96	$38.46	$32.24	$38.22
Feb-12	320,000	128,000	94,720	$1.99	$37.72	$31.73	$38.03
Mar-12	320,000	138,240	99,520	$1.85	$35.94	$30.08	$35.98
Apr-12	320,000	128,000	102,400	$1.74	$32.23	$26.95	$32.30
May-12	320,000	112,640	87,040	$1.44	$31.69	$22.29	$29.53

TABLE 2 - BPA's Projected Revenue

Month	Revenues by Rate Determinant			Projected IP Revenue	
	Demand ($)	HLH ($)	LLH ($)	Month ($)	Cumulative Total Extended Initial Period* ($)
May-11*	$74,323	$486,758	$513,562	$1,074,643	$1,074,643
Jun-11	$422,400	$4,150,682	$2,265,651	$6,838,733	$7,913,375
Jul-11	$515,200	$4,266,240	$3,154,893	$7,936,333	$15,849,708
Aug-11	$604,800	$5,157,734	$3,134,976	$8,897,510	$24,747,219
Sep-11	$627,200	$4,670,720	$3,303,424	$8,601,344	$33,348,563
Oct-11	$656,000	$4,249,190	$2,834,970	$7,740,160	$41,088,723
Nov-11	$700,800	$4,266,240	$3,038,458	$8,005,498	$49,094,220
Dec-11	$736,000	$4,691,149	$3,267,405	$8,694,554	$57,788,774
Jan-12	$627,200	$4,922,880	$3,548,979	$9,099,059	$66,887,833
Feb-12	$636,800	$4,828,160	$3,005,466	$8,470,426	$75,358,259
Mar-12	$592,000	$4,968,346	$2,993,562	$8,553,907	$83,912,166
Apr-12	$556,800	$4,125,440	$2,759,680	$7,441,920	$91,354,086
May-12*	$386,477	$3,569,562	$1,940,122	$5,896,161	$97,250,246

* Extended Initial Period is May 27, 2011 through May 26, 2012.

In this evaluation of a firm power sale to Alcoa during the Extended Initial Period, BPA has continued to use IP-10 energy and demand rates in Tables 1 & 2.

SUB, EBT100007 at 2, commented that the IP-12 rates may be higher or lower than the IP-10 rates used in this determination. SUB is technically correct, inasmuch as the IP-12 rates must be established in the up-coming rate hearing. Nonetheless, BPA has used the monthly energy and demand rates from the IP-10 rate schedule in Table 1 of this determination because they are, based on current information, a conservative forecast of the IP rates for the period from May 2011 through May 2012. The IP-12 rates – which will ultimately apply during the portion of the Extended Initial Period from October 1, 2011, onward – have yet to be adopted. Furthermore, the Initial Proposal in BPA's BP-12 rate proceeding which will include the proposal for IP-12 rates has not been published. However, BPA's recent Integrated Program Review (IPR) conducted in advance of BPA's upcoming BP-12 rate proceeding (which takes public comment on BPA's proposed internal cost levels for the applicable rate period) has documented a net change in average expenses from FY10-11 to FY-12-13 in the neighborhood of 6 percent (see *2010 Integrated Program Review*, Table 12 - Power Expense Changes Between FY 2010-11 Rate Case and FY 2012-13 Final IPR Spending Levels). As a result, it is highly likely that BPA will propose rates in BP-12 that are higher than those adopted in WP-10 in order to fully recover its higher costs and therefore the IP-12 rate is expected to be higher than the IP-10 rate. Therefore, BPA's use of the IP-10 rate for this determination of Equivalent Benefits is conservative in that BPA would receive more revenues than shown in Table 2 of this determination if the rates adopted in IP-12 are higher than those from IP-10.

c. Forecast of revenues that would be obtained by selling an equivalent amount of surplus power.

BPA routinely shapes its inventory to meet the need of its portfolio of contracts and sells its surplus inventory in the Pacific Northwest power market as described in BPA's WP-10 rate proceeding.[10] BPA routinely forecasts Mid-C electricity prices consistent with the methodology described in the WP-10 rate proceeding to value these purchases and sales.[11] For this analysis, BPA updated the inputs and assumptions used to forecast electricity prices as described in Attachment C. In particular, BPA updated its natural gas price forecast – one of the inputs used to forecast electricity prices – to reflect more contemporary natural gas market fundamentals. This forecast of natural gas prices was used in BPA's final Resource Program released September 2010.[12]

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[10] *See* Alcoa ROD at 39. Refer also to section 2.4 of the *Risk Analysis and Mitigation Study* in the WP-10 rate proceeding for a more complete description of the operating risk factors BPA faces in the course of doing business – in particular "the variation in hydro generation due to the variation in the volume of water supply from one year to the next…" which significantly impacts market prices, our need for shaping purchases and our ability to make surplus sales. *See* WP-10-FS-BPA-04 beginning on page 21.

[11] BPA employed its electricity price forecast for multiple purposes in the WP-10 rate proceeding as outlined in the *Market Price Forecast Study*. The study also details how BPA established its forecast of Mid-C electricity prices in the WP-10 rate proceeding. *See* WP-10-FS-BPA-03, beginning on page 1.

[12] BPA's natural gas forecast used in the WP-10 rate proceeding is outlined in section 3.3 of the Market Price Forecast Study. *See* WP-10-FS-BPA-03, beginning on page 11. BPA's more contemporary understanding of natural gas market fundamentals caused a lowering of its natural gas price forecast used in the final Resource Program. The primary reasons for BPA's recent reductions became apparent in the progression of time since the natural gas price forecast for the WP-10 rate proceeding was constructed. These are: a) continued strength of natural gas production despite steep reductions in rig counts, b) continued slow recovery of natural gas demand – particularly on the industrial side – in that growth in natural gas demand is slower than growth in natural gas production, c) near record amount of natural gas in storage, d) reduced risk of hurricane impact on supply now that the 2010 hurricane season has one month remaining. *See also* Short-Term Energy Outlooks from the EIA for September showing the EIA lowered its

In the absence of selling 320 aMW of firm power to Alcoa's Intalco Plant every hour, BPA would have one less firm power requirement sale in its aggregated portfolio load shape. As such, BPA would have approximately 320 aMW of surplus energy to sell in the market on an average annual basis. As illustrated in Table 3, BPA has forecast the revenues it would otherwise obtain from the market by incorporating BPA's updated inputs and assumptions in the development of the electricity price forecast used in this analysis of the Extended Initial Period.[13]

TABLE 3 - BPA's Forecasted Revenues Obtained from the Market

Month	Forecasted Market		Forecasted Revenues Obtained from the Market			
	HLH Price ($ / MWh)	LLH Price ($ / MWh)	HLH ($)	LLH ($)	Month ($) (HLH + LLH)	Cumulative Total Extended Initial Period* ($)
May-11*	$33.34	$20.39	$512,115	$469,732	$981,847	$981,847
Jun-11	$33.30	$18.93	$4,433,366	$1,841,179	$6,274,545	$7,256,392
Jul-11	$39.01	$26.61	$4,993,504	$2,929,105	$7,922,609	$15,179,001
Aug-11	$42.08	$30.62	$5,817,221	$3,056,957	$8,874,178	$24,053,179
Sep-11	$39.54	$28.68	$5,060,801	$2,936,601	$7,997,401	$32,050,580
Oct-11	$42.80	$33.28	$5,697,575	$3,493,539	$9,191,114	$41,241,694
Nov-11	$43.23	$33.28	$5,533,260	$3,418,279	$8,951,539	$50,193,233
Dec-11	$45.05	$35.61	$5,996,634	$3,737,185	$9,733,818	$59,927,052
Jan-12	$46.59	$34.53	$5,963,978	$3,800,764	$9,764,742	$69,691,794
Feb-12	$46.48	$34.75	$5,949,490	$3,291,170	$9,240,660	$78,932,454
Mar-12	$45.52	$33.36	$6,292,245	$3,319,492	$9,611,737	$88,544,191
Apr-12	$40.75	$27.72	$5,216,283	$2,838,321	$8,054,604	$96,598,795
May-12*	$38.78	$22.04	$4,368,143	$1,918,767	$6,286,910	$102,885,705

* Extended Initial Period is May 27, 2011 through May 26, 2012.

As detailed in the Gas Price Forecast sub-section further below, BPA's forecasts of natural gas prices for the Henry Hub have been progressing steadily downward recently. BPA's natural gas price forecasts have fallen steadily since the WP-10 Final Proposal was published in July, 2009. The gas prices from the draft Resource Program that was used in the Alcoa ROD was lower than that used in the WP-10 Final Proposal. Subsequently, the natural gas forecast used in the final Resource Program was reduced even further. In addition, as SUB notes in its comments, the EIA released a *Short-Term Energy Outlook* during the comment period that indicated its price expectations for 2011 are 4 percent below what they were in September. As such, it is not unreasonable to assume that BPA's forecast of natural gas prices for the BP-12 rate proceeding could decline further given market developments since July, when the gas price forecast for the final Resource Program was completed. As a result, this gas price forecast is a conservative assumption not only because BPA's resulting forecast of market prices for electricity could decrease further, but also because BPA's $102.9 million of Forecast Revenues Obtained from the Market in Table 3 represents the entire opportunity cost

forecast Henry Hub Spot Price average for 2011 to $4.76 per MMbtu, *Short-term Energy Outlook*, DOE EIA, September 8, 2010, at 6.

[13] DSI load is assumed to include the total market load used to forecast the revenues obtained from the market at this stage. Please refer to the section on Demand Shift for how a shift in demand can affect BPA's surplus sales revenues.

contributing to this determination of Equivalent Benefits by BPA. In other words, if the forecast revenues BPA could otherwise obtain from selling power into the market were to decline further while the revenues BPA would earn from the firm sale of 320 aMW to Alcoa at the IP rate remain the same, then BPA's forecast of Equivalent Benefits would improve by the same amount.[14]

Net Benefit (IP – Market)

BPA determined its net benefit of serving Alcoa's Intalco Plant at the IP rate for each month by subtracting the opportunity cost forecast of revenues at market prices detailed in Table 3 from the projected IP revenues described in Table 2. BPA's net benefit before adjustments is illustrated in Table 4:

TABLE 4 - BPA's Net Benefit before Adjustment

Month	Net Revenue or (Cost) Month ($)	Net Revenue or (Cost) Cumulative Total Extended Initial Period* ($)
May-11*	$92,796	$92,796
Jun-11	$564,188	$656,983
Jul-11	$13,724	$670,707
Aug-11	$23,332	$694,040
Sep-11	$603,943	$1,297,982
Oct-11	($1,450,954)	($152,972)
Nov-11	($946,041)	($1,099,013)
Dec-11	($1,039,265)	($2,138,278)
Jan-12	($665,683)	($2,803,961)
Feb-12	($770,235)	($3,574,195)
Mar-12	($1,057,830)	($4,632,025)
Apr-12	($612,684)	($5,244,709)
May-12*	($390,749)	($5,635,459)

* Extended Initial Period is May 27, 2011 through May 26, 2012.

d. Calculation of the net financial value of tangible benefits of selling power to Alcoa as opposed to selling an equivalent amount of power on the market.

Consistent with the methodology described in the Alcoa ROD, BPA has identified a number of tangible benefits to BPA that would not be achieved by a market sale of power compared to selling to Alcoa at the IP rate during the Extended Initial Period. BPA

[14] This pattern of forecasts of natural gas prices progressing steadily downward recently has been observed in the passage of time since the Alcoa ROD as illustrated in Figure 1 (p. 34). So, for example, if BPA's forecast of electricity prices declined 8.7 percent then BPA's analysis would demonstrate how the projected revenues BPA recovers from a 12-month IP sale to Alcoa during the Extended Initial Period (from May 27, 2011, through May 26, 2012) exceed by approximately $37.6 million the forecast revenues that BPA would otherwise obtain from the market – nearly 8 times the mean forecast of $4.8 million. *See also* the Market Price Risk sub-section and Figure 2, *supra* section V.h.

conducted an economic analysis to determine the net value of those benefits for the Extended Initial Period. There were other, less tangible benefits accruing to BPA but assigning a financial value to those would have been more subjective, and based on the analysis below, doing so was unnecessary.[15]

Value of Reserves

The Block Contract requires that Alcoa make contingency reserves available to BPA, reserves that would not be available from making a typical market sale. BPA takes into account the value of the reserves Alcoa is required to make available to BPA during the Extended Initial Period. Sales at the IP rate reflect the value of BPA's right to obtain contingency reserves.[16] Specifically, the energy rate tables in the IP-10 rate schedule include an $0.80 per MWh credit for the value of these reserves. Therefore, BPA's net benefit above compares a surplus power sale to a sale of power at the IP rate with reserves. We have adjusted for this by adding back a value of reserves that provides an equal and opposite offset to the $0.80 per MWh credit for the value of reserves in the IP-10 rate schedule.[17] As illustrated in Table 5a, this is done for every megawatt hour not sold to Alcoa:

TABLE 5a - BPA's Net Benefit Adjustments

Value of Reserves

Month	Month ($)	Cumulative Total Extended Initial Period* ($)
May-11*	$30,720	$30,720
Jun-11	$184,320	$215,040
Jul-11	$190,464	$405,504
Aug-11	$190,464	$595,968
Sep-11	$184,320	$780,288
Oct-11	$190,464	$970,752
Nov-11	$184,576	$1,155,328
Dec-11	$190,464	$1,345,792
Jan-12	$190,464	$1,536,256
Feb-12	$178,176	$1,714,432
Mar-12	$190,208	$1,904,640
Apr-12	$184,320	$2,088,960
May-12*	$159,744	$2,248,704

* Extended Initial Period is May 27, 2011 through May 26, 2012.

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[15] *See* Alcoa ROD, pages 72-82.

[16] Sales at the IP rate require the provision of the DSI Minimum Operating Reserve – Supplemental. The Block Contract is an IP sale and, accordingly, it requires that Alcoa make such a contingency reserve available to BPA, as defined in section 2.19 and implemented by section 10.1 and Exhibit F to the Block Contract.

[17] In other words, BPA has increased the IP rate by the value of reserves credit for purposes of this analysis so that the comparison to a surplus sale into the market is on an "apples to apples" basis.

In this determination, BPA has continued to use the $0.80 per MWh credit for the value of reserves included in the IP-10 energy rates table. The IP-12 rates are not yet established or proposed.

In its comments, PNGC asserts "BPA has vastly overvalued the reserves that it obtains under the Block Contract by means of curtailment." *See* PNGC, EBT 100011, at 3. To make its point PNGC argues that: "BPA's assessment of value is the product of Alcoa's annual megawatt-hour purchase commitment multiplied by the $0.80 per MWh discount that BPA decided to give Alcoa in the WP-10 rate case. This is an arithmetic calculation of the cost of the reserves, not a rational explanation of their economic value." *See* PNGC, EBT 100011, at 3-4. BPA disagrees with PNGC's statement that it has vastly overvalued the reserves that it obtains under the Block Contract. Precisely as PNGC describes, the value of reserves ascribed in this determination of Equivalent Benefits *is* "the arithmetic calculation of the *cost* of the reserves" as established in BPA's WP-10 rate proceeding and included in the IP-10 energy rates adopted in the same proceeding. *See* WP-10-A-02-AP02 at 49.

To further illustrate its point, PNGC extrapolated that "BPA is effectively paying Alcoa $1,250 per MWh for reserves." Assuming, as PNGC does, that the frequency of actual reserve deployments does not change over time, PNGC creates a red herring when it states that BPA is effectively paying Alcoa $1,250 per MWh for reserves *deployed*. The contingency reserves provided by Alcoa are required to be available on *every* hour – whether they are *deployed or not* – consistent with NERC and WECC criteria and consistent with BPA's Business Practices for Operating Reserves established by its Transmission Services organization. As such, BPA holds fewer contingency reserves from the FCRPS *on every hour* than would otherwise be required.[18] As a result, this FCRPS capacity that in the absence of the Block Contract would have been set aside to provide contingency reserves, is now available for another use.[19]

Issues with the economic value of the reserves made available by Alcoa that parties raise will be addressed during the BP-12 rate proceeding. They are only germane to this determination to the extent BPA's continued use of the $0.80 per MWh credit for the value of reserves included in the IP-10 energy rates table is implicated for FY 2012. It is not. As described earlier, BPA has documented a net change in average expenses from FY10-11 to FY-12-13 in the neighborhood of 6 percent (see *2010 Integrated Program Review*, Table 12 - Power Expense Changes Between FY 2010-11 Rate Case and FY 2012-13 Final IPR Spending Levels). As a result, it is likely that BPA will adopt rates in BP-12 that are higher than those adopted in WP-10 in order to fully recover it higher

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[18] As is made clear in the DSI Reserve Log maintained by BPA and referenced by PGNC in its extrapolation, EBT100011 at 4, BPA has called on the reserves from Alcoa without any forewarning on a variety of days and hours. Alcoa's performance has been compliant with the required criteria set forth in BPA's Business Practices for Operating Reserves established by its Transmission Services organization.

[19] "BPA did not de-rate the value of the reserve because the stand-ready value of the reserve provided by a power sale to a DSI gives BPA roughly full value in that it can displace operational capacity that would have otherwise been utilized as Supplemental Operating Reserve." *See* Alcoa ROD at 30-31.

costs. This has two implications for BPA's continued use of the $0.80 per MWh credit for the value of reserves included in the IP-10 energy rates table: a) the $0.80 per MWh credit is itself based on a formula using a separate cost-based rate; and b) the IP-12 rate is expected to be higher than the IP-10 rate. First, the cost-based rate for Generation Inputs that is an input to BPA's calculation is expected to increase because BPA's expenses are increasing, which, all else being equal, would cause the credit for the value of reserves included in the IP-12 energy rates table to increase in absolute value, not decrease, resulting in a larger credit for the value of reserves. Second, even if BPA were to reduce the credit for the value of reserves in the BP-12 rate proceeding, the difference from this forecast of $0.80 per MWh is likely to be more than offset by the difference from the IP-10 rate used in this determination and the IP-12 energy rates adopted in the BP-12 rate proceeding. For the forgoing reasons, BPA's continued use of the $0.80 per MWh credit for the value of reserves included in the IP-10 energy rates table is conservative.

Avoided Transmission and Ancillary Services Expenses

When BPA makes a sale to a DSI, all DSI customers – including Alcoa – cover the cost of transmission and ancillary services through their own transmission contracts with BPA's Transmission business line. Market prices for power in the Pacific Northwest, on the other hand, assume power is delivered by the seller to the Mid-Columbia trading hub (Mid-C); thus the seller pays for the cost of transmission. Power Services (PS) is the organization within BPA that is responsible for the management and sale of Federal power. PS must pay the transmission and ancillary services costs to move surplus power to the Mid-C delivery point in order to realize the full market value for its surplus sales. PS maintains an inventory of transmission products and services to deliver the surplus power it intends to sell.

However, this transmission product inventory is not sufficient to deliver all of the surplus power PS would sell under all load and resource conditions, especially under high stream flows. As a result, there is a subset of load and resource conditions under which PS would incur incremental costs for transmission and ancillary services to deliver incremental surplus energy sales, if PS did not sign contracts to serve the DSI loads. The planned transmission and ancillary services expenses to address both the expected expenses and their uncertainty were addressed in the WP-10 rate proceeding and are expected to be addressed in subsequent BPA rate proceedings.[20] Since PS's overall marketing strategy is to serve all its loads out of inventory and to balance its supply to meet any within-year deficits with short-term purchases, the incremental transmission and ancillary services costs are avoided when BPA makes firm power IP sales to the DSIs.

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[20] Refer to section 4 of the *Revenue Requirement Study*, WP-10-FS-BPA-02 and section 2.4 of the *Risk Analysis and Mitigation Study* in the WP-10 rate proceeding. BPA does not anticipate changing the methodology for addressing planned transmission and ancillary service expenses in the WP-12 rate proceeding.

PS valued these avoided transmission and ancillary services costs for the Extended Initial Period using the same methodology used in the WP-10 rate proceeding to establish the total costs and risks associated with PS's inventory of transmission products and services. In these computations, both fixed, take-or-pay costs and variable incremental transmission and ancillary service costs were computed under 3,500 load and resource conditions for each month. Incremental transmission and ancillary services costs were computed by comparing the amount of surplus energy available to the monthly excess amount of firm transmission products in the PS inventory.

Tariff costs established by BPA's Transmission Services organization were applied to the amount of surplus energy in excess of the PS transmission products inventory. Total monthly transmission and ancillary services costs were computed assuming no service to the DSIs and DSI service of 340 aMW.[21] The average total monthly expense values of the 3,500 games were computed with and without service to the DSIs and the differences were taken to determine the avoided PS transmission and ancillary services costs when PS makes these 340 aMW of IP sale(s) to the DSIs. For purposes of this analysis, Alcoa has been allotted 94.1% of this PS benefit in each month as illustrated in Table 5b below. This percent allotment is the result of the proportion of the megawatt amounts during the Extended Initial Period, and as depicted in Table 1 above, as compared to the 340 aMW forecast for all DSI customers.

TABLE 5b - BPA's Net Benefit Adjustments

Avoided Tx and Ancillary Service Costs

Month	Month ($)	Proportional Month ($)	Cumulative Total Extended Initial Period* ($)
May-11*	$92,056	$86,641	$86,641
Jun-11	$578,435	$544,409	$631,050
Jul-11	$399,662	$376,153	$1,007,203
Aug-11	$90,001	$84,706	$1,091,909
Sep-11	$58,167	$54,745	$1,146,655
Oct-11	$35,084	$33,020	$1,179,675
Nov-11	$100,669	$94,747	$1,274,422
Dec-11	$135,000	$127,059	$1,401,481
Jan-12	$432,858	$407,396	$1,808,877
Feb-12	$379,106	$356,805	$2,165,682
Mar-12	$434,459	$408,902	$2,574,584
Apr-12	$570,075	$536,541	$3,111,125
May-12*	$650,127	$611,884	$3,723,009

* Extended Initial Period is May 27, 2011 through May 26, 2012.

BPA continues to value avoided transmission and ancillary services costs for the Extended Initial Period using the tariff costs adopted by Transmission Services in the TR-

[21]This number is comprised of 320 aMW for Alcoa and 20 aMW for Port Townsend Paper Company.

10 rate proceeding. The applicable tariff costs from the BP-12 rate proceeding are not yet established or proposed.

SUB, EBT100007 at 4, asserts that the "month to month variation… is proportionately different than the month to month variation in the Alcoa ROD" and PNGC, EBT100011 at 4, claims that BPA's "assumption that power sold to Alcoa can only be sold at Mid-C is incorrect." SUB is correct that the month-to-month variation is different in this determination than it was in the Alcoa ROD. This is because BPA's forecast of the benefits accruing from Avoided Transmission and Ancillary Services reflects the best information currently available to BPA. Specifically, BPA's forecast of the benefit accruing from Avoided Transmission and Ancillary Services costs, as described in the Alcoa ROD at 42-43, reflects the "load and resource conditions under which [BPA's Power Services] would incur incremental costs for transmission and ancillary services to deliver incremental surplus energy sales."

For this determination, BPA updated its inputs using the same methodology used in the WP-10 rate proceeding, including but not limited to the hydro regulation studies that produce forecasts of hydroelectric generation, to develop its 3,500 game distribution of load and resources conditions. As a result, BPA's updated forecast of the financial benefit from avoided transmission and ancillary services costs is higher in some months and lower in others when compared with the same months published in the Alcoa ROD. Specifically, the forecasts of the financial benefit to BPA in May 2011 of avoided transmission and ancillary services costs was $765,645 in the Alcoa ROD (see Alcoa ROD, Table 5b at 44) and is $570,746 in this determination (the sum of $92,056 from Table 5b and $476,690 from Attachment C to the analysis released in October 6, 2010), whereas the forecasts of the financial benefit to BPA in June 2011 of avoided transmission and ancillary services costs was $669,032 in the Alcoa ROD (see Alcoa ROD, Table 5b at 44) and is $578,435 in this determination. Whether or not one's definition of month-to-month variation is looking at the relative change in the same month between the Alcoa ROD and this determination or the relative change between consecutive months, May and June in this example, from the Alcoa ROD and this determination, the conclusion is the same in that the month to month variation is different and the differences are an appropriate reflection of the updated inputs.

In addition, SUB questioned whether the "month to month variation …is due to a shift in market price or some other variable." EBT100007 at 4. As described more fully above and consistent with the Alcoa ROD at 43, tariff costs established by BPA's Transmission Services organization, or our forecast of tariff costs yet to be established, and not market prices, are the input applied to the amount of surplus energy in excess of the PS transmission products inventory resulting from the 3,500 game distribution when assuming no DSI service and assuming 340 aMW of DSI service. The difference between these two results is the forecast of the monthly value of the avoided transmission and ancillary service costs. Therefore, the updated load and resource inputs used in the forecast of the financial benefit to BPA from avoided transmission and ancillary services costs for this determination impact the month-to-month variation of dollars resulting from this benefit, but BPA's updated forecast of market prices does not.

PNGC comments that: "BPA can and does sell power in wholesale markets to other customers, including preference and non-preference customers, with BPA Power as the delivery point, not exclusively Mid-C. The assumption that power sold to Alcoa can only be marketed at Mid-C is incorrect. Therefore, BPA's adjustment based on these assumed avoided costs is improper and invalid." EBT100011 at 4-5. PNGC suggests that if BPA disagrees then BPA should include in the record documentation that BPA cannot sell any or all of the power proposed to be sold to Alcoa without delivering it to Mid-C.

BPA disagrees with PNGC on this point. On the one hand, firm power customers of BPA, such as the DSIs and PF customers, are required to provide their own transmission and ancillary services, at their cost, from different points of receipt (i.e. the federal busbar) within the federal transmission system to ensure the delivery of such power to the location where it will be consumed. On the other hand, the vast majority of BPA's surplus power sales are delivered products, meaning BPA must use transmission, at our cost, to make these surplus sales. As already noted, this is because the market participants typically expect the electricity to be delivered at a market trading hub, such as Mid-C. Similarly, the market price forecast used to establish BPA's forecast revenues obtained from the market in Table 3 above "assume[s] power is delivered by the seller to Mid-Columbia trading hub (Mid-C)", as indicated in the Alcoa ROD at 42. This means that BPA – forecast to be net seller – is expected to incur transmission and ancillary services costs to deliver the power at Mid-C for purchase by others at that point. This is also the same manner that the modeling tools BPA employs in its rate proceedings model BPA's costs and risks associated with transmission and ancillary services. *See* WP-10-FS-BPA-04 at 30. As a result, BPA has rightly included the value of the benefit of Avoided Transmission and Ancillary Services costs in the EBT.

Demand Shift

When BPA serves the DSI loads – including Alcoa – and they operate – as opposed to not operating if BPA does not sell to them – all of BPA's surplus sales realize increased revenues because the mean value of prices for electricity in Western power markets are higher than they would otherwise be had the DSI loads not consumed electricity from Western power markets. BPA has forecast these increased revenues by reducing loads in the PNW by 340 aMW in each month for each of the 3,500 games AURORA$^{xmp®}$ simulated for the forecast used in Table 3 above. This lowered the mean price forecast by a 12-month average of \$0.38 per MWh and by \$0.45 per MWh for fiscal years 2011 and 2012 respectively.[22] The monthly difference resulting from this lower mean price forecast was then multiplied by BPA's monthly surplus energy from BPA's recent forecasts of hydroelectric generation for FY 2011 and FY 2012 – outputs of HYDSIM

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[22] AURORA$^{xmp®}$ is an electric energy market model that is owned and licensed by EPIS, Incorporated. The model assumes a competitive market pricing structure as the fundamental mechanism underlying how it estimates the wholesale electric energy market prices during the term of an analysis. In a competitive market, at any given time, electric energy market prices should be based on the marginal cost of production, which is the variable cost of the last generating unit needed to meet energy demand.

from late July and early August of 2010 – to determine the increased revenues available to BPA's surplus sales when BPA makes an IP sale(s) to the DSIs – including a firm power sale to Alcoa during the Extended Initial Period. For the purposes of this analysis, Alcoa has been allotted 94.1% of this benefit to BPA in each month as illustrated in Table 5c below. This percent allotment is the result of the proportion of the average megawatt amounts in the Block Contract, and as depicted in Table 1 above, as compared to the 340 aMW forecast for all DSI customers.

TABLE 5c - BPA's Net Benefit Adjustments

	Demand Shift		
Month	Month ($)	Proportional Adjusted Month ($)	Cumulative Total Extended Initial Period* ($)
May-11*	$122,511	$115,304	$115,304
Jun-11	$1,000,365	$941,520	$1,056,824
Jul-11	$411,523	$387,316	$1,444,140
Aug-11	($19,968)	($18,794)	$1,425,346
Sep-11	$26,443	$24,888	$1,450,234
Oct-11	($59,599)	($56,093)	$1,394,140
Nov-11	$31,970	$30,090	$1,424,230
Dec-11	$10,031	$9,440	$1,433,670
Jan-12	$424,453	$399,485	$1,833,156
Feb-12	$371,928	$350,050	$2,183,206
Mar-12	$542,456	$510,547	$2,693,752
Apr-12	$643,772	$605,903	$3,299,656
May-12*	$1,193,297	$1,123,103	$4,422,759

* Extended Initial Period is May 27, 2011 through May 26, 2012.

SUB commented:

> BPA fails to account for the impact associated with BPA's demand shift methodology. Essentially BPA's demand shift analysis shows that market pricing is higher if BPA serves the Alcoa load. This means that BPA balancing purchase costs associated with market purchases to serve preference customers are higher, Tier II purchases made by BPA to serve preference customers are higher, and Tier II market acquisitions not offered by BPA, but purchased by preference customers to meet obligations under BPA contracts, are higher.

EBT 100007 at 6-7. As an example, SUB suggests that recent purchases by BPA to cover Tier 2 load obligations (made in April and May 2010), at $42 and $47/MWh, were $0.45/MWh higher due to demand shift increases and would have been $41.55 and $46.55/MWh but for BPA selling to Alcoa. *See* SUB, EBT100007 at 7.

To the contrary, the demand shift values used for this determination do account for BPA's balancing purchases and sales, and the forecast price impacts on them both, in the same manner described in the Alcoa ROD: "The demand shift analysis used both the surplus and deficit energy values to account for the impact of surplus energy sales and balancing power purchases in the computations." *See* Alcoa ROD at 48. Moreover, the prices of Tier 2 purchases made by BPA to serve preference customers are not higher by $0.45 per MWh as SUB asserts and do not force BPA "to charge more for Tier 2 service to its preference customers." *See* PNGC, EBT100011 at 5. Commenters appear to be linking this present determination of Equivalent Benefits and its assumption regarding the demand shift to BPA's determination of Equivalent Benefits in the Alcoa ROD to argue an increase in BPA's past costs. BPA disagrees.

BPA has not yet established rates pursuant to its Tiered Rates Methodology (TRM) and, hence, Tier 2 PF rates have not yet been established. The BP-12 rates, when established pursuant to the TRM, are expected to become effective on October 1, 2011. BPA's prior determination of Equivalent Benefits in the Alcoa ROD on December 21, 2009, of which the demand shift was also a part, covered the period from December 22, 2009, through May 26, 2011 – a period occurring entirely before October 1, 2011. From December 21, 2009 until the time of this determination, BPA's obligation to provide firm power to Alcoa any time after May 26, 2011 was contingent upon either a request from Alcoa initiating BPA's evaluation of extending the Initial Period and a determination by BPA that the EBT was satisfied or a ruling from the Ninth Circuit that BPA need not apply the EBT. *See* Block Contract, sections 5.1.1 and 6. To this day, such a ruling has not been made. BPA received Alcoa's request to extend the initial period on September 2, 2010.

This determination of Equivalent Benefits, of which the demand shift is also a part, was initiated in response to Alcoa's request and does include eight months in FY 2012 from October 1, 2011 through May 26, 2012. However, BPA purchased power to meets its obligation to supply 22 aMW of customer Above High Water Mark Load (Tier 2 purchase obligation) for FY 2012 and the 58 aMW of customer Above High Water Mark Load for FY 2013 in April and May 2010.[23] These were purchases made at forward market prices prevailing after BPA's prior determination on December 21, 2009, and before Alcoa's request on September 2, 2010. *See* BPA Bulk Hub Purchase Notification for Service at Tier 2 Rates, dated April 7, 2010 and May 25, 2010. The demand shift is BPA's forecast of the impact an assumed increment of DSI load will have on market-clearing prices for electricity at Mid-C. While forward market prices for future delivery are impacted by the market participants view of what loads might be in the future, market participants, including BPA, did not know whether or not BPA's obligation to provide firm power to Alcoa would be extended past May 26, 2011 at the time BPA's purchases for Tier 2 were made in April and May 2010. Therefore, prices for these Tier 2 purchases were not impacted by the demand shift used in BPA's determinations of Equivalent Benefits for the DSIs.

In addition, any acquisitions by preference customers, or their representatives, to buy power in advance to supply their Above High Water Mark load are similarly unaffected. Even if they were, BPA does not consider direct costs to other parties in the EBT. The

[23] The Tier 2 purchases were made well in advance to lock into a price so as not to be subject to market-clearing prices during their period of delivery.

test is designed to evaluate the impact to BPA only. Nonetheless, issues with cost allocation that parties raise will be addressed during the BP-12 rate proceeding.

e. Conclusion of Equivalent Benefits Test

The preceding analysis demonstrates how the projected revenues BPA would recover from a 12-month IP sale to Alcoa during the Extended Initial Period (from May 27, 2011 through May 26, 2012) exceed by approximately $4.8 million the projected revenues that BPA would otherwise obtain from the market. *See* Table 6. BPA's methodology for making this determination is based, to the extent possible, on modeling tools used in BPA's power rate cases. That process includes discovery, testimony, rebuttal testimony, and cross examination prior to a final determination by the Administrator. Further, the analysis is marked by thorough and thoughtful consideration of market fundamentals and other factors that strengthen the integrity of the results.

TABLE 6 - BPA's Net Benefit after Adjustments

Month	BPA's Adjusted Net Revenue or (Cost)					
	Net Revenue or (Cost) (A) Month ($)	Value of Reserves (B) Month ($)	Avoided Tx Costs (C) Month ($)	Demand Shift (D) Month ($)	A + B + C + D Month ($)	Cumulative Total Extended Initial Period* ($)
May-11*	$92,796	$30,720	$86,641	$115,304	$325,461	$325,461
Jun-11	$564,188	$184,320	$544,409	$941,520	$2,234,437	$2,559,898
Jul-11	$13,724	$190,464	$376,153	$387,316	$967,656	$3,527,554
Aug-11	$23,332	$190,464	$84,706	($18,794)	$279,709	$3,807,263
Sep-11	$603,943	$184,320	$54,745	$24,888	$867,896	$4,675,159
Oct-11	($1,450,954)	$190,464	$33,020	($56,093)	($1,283,563)	$3,391,595
Nov-11	($946,041)	$184,576	$94,747	$30,090	($636,629)	$2,754,967
Dec-11	($1,039,265)	$190,464	$127,059	$9,440	($712,301)	$2,042,666
Jan-12	($665,683)	$190,464	$407,396	$399,485	$331,662	$2,374,328
Feb-12	($770,235)	$178,176	$356,805	$350,050	$114,797	$2,489,124
Mar-12	($1,057,830)	$190,208	$408,902	$510,547	$51,827	$2,540,951
Apr-12	($612,684)	$184,320	$536,541	$605,903	$714,080	$3,255,032
May-12*	($390,749)	$159,744	$611,884	$1,123,103	$1,503,982	$4,759,013

* Extended Initial Period is May 27, 2011 through May 26, 2012.

V. ADDITIONAL ISSUES

This section addresses BPA's approach to several issues related to the EBT, but not directly addressed in the application of the test.

a. Legal implications of serving Alcoa from existing inventory

PNGC, EBT100011 at 3, argues that serving, via the EBT, Alcoa from existing inventory, while making purchases to serve preference customer Tier 2 load, appears to violate BPA's obligations under section 5(a) of the Northwest Power Act because BPA would be allocating higher cost resources to preference customers. PNGC also asserts that in conducting the EBT, BPA proposes to sell secondary energy to Alcoa as firm energy, taking a risk that it may have to acquire power and shift costs to others, contrary to section 7(b)(1) of the Northwest Power Act and sound business principles. Similarly, ICNU argues that "BPA should only provide Alcoa with cost based power if it is consistent with sound business principles and after BPA has met all its preference customers' net requirements with cost based power at Tier 1 rates." EBT100010 at 2. BPA disagrees with PNGC's and ICNU's arguments. While they were addressed for the most part in the Alcoa ROD, the arguments now arise in the context of BPA's implementation of tiered rates for preference customers beginning October 1, 2011. While the arguments about tiered rates could and should have been been made in the comment process on the Alcoa contract, BPA nonetheless addresses them here in order to clearly convey the important distinction between cost allocation and rate design.

Similar cost recovery and cost allocation issues were addressed, and rejected, at pages 13-18 of the Alcoa ROD as follows:

> In past comments, particularly comments related to the CFAC Amendment, some of BPA's preference customers have expressed a belief that, even if BPA offers to sell power to DSIs at the IP rate, that rate must recover the full incremental costs of any resources obtained to support DSI contracts. *See e.g.*, NRU, CFA090001 at 2 (arguing that "DSIs have no right to continued BPA service" and a discretionary sale must be consistent with "establishing rates at the lowest possible cost consistent with sound business principles"); SUB, CFA090003; and Canby, CFA09002. [Footnote omitted.] Even in the most recent round of comments, preference customer groups have continued to suggest that service to Alcoa would constitute a "subsidy." See e.g., PPC at 9; ICNU at 5; SUB at 18; WPAG at 9.
>
> A central holding of the Court's opinion in *PNGC I* is that, if the Administrator exercises his discretion to offer to sell power to the DSIs, any initial offer must be at the IP rate. 580 F.3d 817. In support of its conclusion that any initial offer of DSI service must be at the IP rate, the Court observed that the legislative history of the Northwest Power Act "contains extensive evidence that Congress intended the IP rate to be the default price for sales of power to the DSIs." *Id.* 814. In this connection, the Court noted that legislative history states that "Section 7(c) prescribes the rates applicable to direct service industrial customers" (H.R. Rep. No. 96-976, pt. 1, at 69) and is the rate which "applies to all 'Industrial Firm' sales to BPA's direct-service industries . . . [for] 1985-86 and all future [sales]." (S. Rep. No. 96-272 at 59) (emphasis added in Opinion). The Court adds that, to the extent BPA decides to exercise its discretion to offer power to the DSIs, the *Kaiser* case "supports . . . our understanding is that BPA does have an obligation to offer the DSIs a cost-based rate—namely, the IP rate—before declaring energy as surplus under § 839c(f) and selling it to the DSIs at a market-based—or other—FPS rate." *Id.* at 817 (emphasis added).
>
> The "cost-based rate" referred to is not, as some preference customers have suggested, one that reflects the prevailing prices for power available on the open market, but is rather the IP rate, a rate that is statutorily tied to

the PF rate, 16 U.S.C. § 839e(c)(2). Thus, the Court recognized that the IP rate is a cost based rate, *i.e.*, a rate that together with BPA's other rates are based on and established to recover BPA's total system costs, and not a rate targeted to recover the incremental costs of resources, as some commenters have argued, that might be needed to replace system capability in order to support all of BPA's contractual obligations.

In addition, the Court set out the applicable rate directive, which supports the view that the IP rate is not an incremental cost rate. See, *id.*, at 16556, citing 16 U.S.C. § 839e(c) (Section 7(c) of the NPA). The general statutory command is that the section 7(c) rate directive requires that the IP rate be "equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." 16 U.S.C. § 839e(c)(1)(B). The determination of equitability is required to be based upon the rate BPA charges its preference customers, with certain adjustments. 16 U.S.C. § 839e(c)(2). Those adjustments include the inclusion of an "industrial margin" which reflects the "overhead" that preference customers charge their own industrial customers. Also included in the IP rate is a credit for reserves that DSIs provide in connection with 839e(c)(3).

It is difficult to understand, as PPC and other commenters apparently contend, how the IP rate established pursuant to section 7(c), which provides very explicit and detailed requirements for developing the rate, could recover from the DSIs the incremental cost of any acquisitions required to replace system capacity in support of DSI service and still be "equitable" in relation to the rates of industrial customers of BPA's public customers, who purchase power to serve their industrial loads at the PF (preference) rates. As the language of section 7(c) shows, it was not Congress's intent to have BPA charge the DSI customers rates that are inequitable as compared to the retail rates charged by preference customers to their industrial consumers. Rather, Congress intended to closely link the IP rate to the PF rate.

This issue of whether BPA should establish the IP rate on the basis of cost causation was fully aired in BPA's WP-10 rate proceeding. See 2010 Wholesale Power and Transmission Rate Adjustment Proceeding (BPA-10) Administrator's Final Record of Decision, (July 2009), Section 12.2, Section 7(c) Rate Directive, at pages 200-212, where BPA concluded that BPA is required to set the IP rate, as it has since 1985, consistent with the relevant provisions of section 7(c) of the Northwest Power Act. BPA has never interpreted these provisions to mean that the IP rate can be set based on principles of cost causation and sees no reason to deviate from its historical practices.

In short, the section 7(c) statutory rate directive specifically mandates the criteria by which the IP rate will be developed and there is no legal basis to conclude that it must be set to recover the incremental cost of any acquisitions made by BPA to replace resources if needed to support DSI sales. The Court in *PNGC* understood the nature of the IP rate when it held that any initial offer of service must be at the IP rate. 830 F.3d at 817. Thus, if the comments are taken at face value, some commenting parties would require the Administrator to ignore the rate-setting directive, which would be contrary to law, or make an initial offer at a rate other than the IP rate, which is prohibited by the *PNGC* opinion. Accepting such an argument would be in direct contravention of the Court's holding in the very case being relied upon by the parties who are raising it.

Even though BPA projects no need to do so during the Initial Period of the Block Contract, the Court recognized further that BPA may make market purchases to support DSI sales: "Congress also vested BPA with the authority to acquire power, including purchasing energy on the open market, if needed to meet its contractual obligations... [and] BPA has the statutory authority to sell power to DSIs at valid contract rates and to purchase at market rates the power to serve those contracts." 830 F.3d at 819. Additionally, in a separate Ninth Circuit opinion, the Court did not agree with the preference customers' assertion, now apparently recast in response to *PNGC II*, that no costs associated with DSI service can be allocated to the preference rate:

> According to petitioners, "Entering contracts to sell power to the DSIs when BPA has none to sell them is unlawful.... The only way the post-2001 contracts with the DSIs can be lawfully performed is to require the DSIs to pay the full costs of service." In other words, petitioners asserted that BPA could not allocate to its preference customers any of the costs of purchasing power at market prices to serve the DSIs.

Golden Northwest Aluminum, Inc. v. Bonneville Power Admin., 501 F.3d 1037, 1044 (9th Cir. 2007). The Court rejected petitioners' arguments. Instead, the Court in GNA concluded that BPA can "use any remaining FBS resources—including FBS replacement resources—to supply its DSI customers" and BPA "is entitled to charge preference customers a rate that reflects the total cost of all FBS resources, including resources acquired to replace losses in the generation capabilities of BPA's primary resources." *Id*.

The *PNGC* Court recognized that providing such service at the IP rate, as mandated by Congress, might itself provide some level of subsidy. The Court refers to the IP rate as the rate that BPA "is statutorily required to offer" and reflects "the primary benefit that the class of DSI customers receives under the NPA . . .” *PNGC I* 580 F.3d 792, 825. Further, the *PNGC* Court invalidated the monetized FPS surplus sale, at least in part, because BPA was “subsidizing the DSIs’ smelter operations beyond what it is obligated to do,” *i.e*., beyond what is provided for by Congress through the IP rate directive. *Id*. at 822 (emphasis added). Thus, if proper application of the IP rate directives results in a benefit to the DSIs, that is simply a consequence of the NPA, and not an illegal subsidy. By the same token, if BPA acquires expensive resources to serve preference customer load growth, and those resource costs increase the PF rate, this in turn results in an increase in the IP rate due to the workings of section 7(c), which means essentially that the DSIs would share some of those expensive resource costs. That too is the way the NPA works and is not an illegal subsidy. Finally, mindful that DSI and certain other features of the proposed Northwest Power Act could substantially increase the PF rate, Congress provided limited cost protection for preference customers in the form of Northwest Power Act section 7(b)(2), 16 U.S.C. § 839e(b)(2). Section 7(b)(2) requires, as one of a series of assumptions in comparing costs under the Act with costs under an alternative case, that the Administrator assume the preference customer load would have included the DSI loads. *Id.* § 839e(b)(2)(A). In other words, in the absence of the Act, BPA would still be serving the load, but indirectly through its preference customers rather than directly. Given that and section 7(c)’s link of the DSI rate to the PF rate, any protection Congress intended to provide preference customers against costs incurred to serve the DSIs is afforded by section 7(b)(2).

Prior to *PNGC I*, BPA’s rates were set based on a monetized power sale to DSI aluminum smelters capped at $59 million per year. Subsequent to *PNGC I*, in the WP-10 rate adjustment proceeding, BPA abandoned the monetized power sale assumption and assumed a direct power sale to both aluminum DSIs and Port Townsend Paper. All such DSI power sales were assumed to be sold at the IP rate established in the WP-10 proceeding. WP-10 established the IP rate pursuant to section 7(c) of the NPA and existing BPA ratesetting methodologies and rate design. Issues were raised by parties regarding the IP ratesetting process and its compliance with *PNGC I* and these issues were dealt with in the WP-10 Final ROD.

In the WP-10 ratesetting process, BPA assumed that it would have a contractual obligation to serve the DSIs at a level of 402 aMW, which included an amount of service to Alcoa. In accord with the *Golden NW* decision, BPA assumed that it would augment the Federal Base System (FBS) resources as needed to meet its expected total obligations, including all PF requirements service to its public customers plus DSI IP service. While BPA did not attribute specific power purchases to specific loads, it can be ascertained from the rate case models that the then-forecasted power purchase expenses, net of additional revenues at the IP rate, increased an average of $37 million in the two-year rate period ($32 million for FY 2010 and $42 million for FY 2011) when compared to power purchase expenses without the assumed power sale to the DSIs. In addition, the risk of both power purchase prices and loads being higher or lower than the level assumed in establishing the amount of power purchases in the revenue requirement was assessed in the risk analysis performed for the rates being established.

The costs of purchased power, including the $37 million average increase, were allocated based on rate directives set forth in section 7 of the NPA. Because these purchased power costs were included in the FBS, section 7(b)(1) specifies that these costs are allocated to the loads of preference customers and the section 5(c) loads of utilities participating in the REP, otherwise known as the PF rate pool. By allocating all of the power purchase costs to the PF rate pool, the DSIs were allocated the costs of more expensive power from section 5(c) exchange resources and new resources. After these power costs are allocated, BPA then adjusts the IP rate to conform to section 7(c) of the NPA by reallocating costs among the rate pools, including the PF rate pool. This reallocation is supported by the legislative history of the NPA, as explained in the WP-10 Final ROD. And, as indicated above, these allocations are further subject to the section 7(b)(2) rate test.

Once established, BPA's rates are set for a two-year period subject, however, to adjustment clauses if BPA's financial reserves are above or below rate case determined thresholds. As such, as long as BPA's financial reserves are between these thresholds, rates will not be adjusted if there are cost overruns or shortfalls. If BPA sells fewer than 402 aMW of power to the DSIs during FY 2010-2011, or if the actual purchase power cost is less than forecasted in the WP-10 rate proceeding, as anticipated, then BPA's financial reserves will be better than expected when setting rates, all else being equal. BPA's latest forecast, discussed in Section V, indicates that BPA now expects that costs and benefits in the Initial Period will be approximately equal. These savings would accrue to BPA's financial reserves and, lacking an FY 2011 adjustment due to other cost and revenue changes, would be available to offset risks in future years, thus reducing upward pressure on BPA's future rates.

Beginning in FY 2012, BPA has established a completely new rate design for the Priority Firm Preference rate. This new rate design was codified in the Tiered Rate Methodology, adopted by the Administrator in the TRM ROD of November 2008. The first rate adjustment proceeding to establish rates pursuant to the TRM will be the WP-12 rate proceeding which is expected to commence in November 2010. As such, no decisions have yet been made about how the IP rate will be established after FY 2011. However, the TRM does not in any way remove or modify any ratesetting

> instructions contained in section 7 of the NPA, including section 7(c) regarding the IP rate, and the Block Contract is explicit that all rate determinations will be made in BPA rate cases.
>
> For all the reasons outlined above, a sale to Alcoa at the IP rate is consistent with statutory requirements and is consistent with sound business principles.

That discussion clearly refutes PNGC's arguments that all costs of DSI service must be borne by the DSIs. That is simply not a requirement of the Northwest Power Act's section 7(b) and 7(c) rate directives.

In addition, PNGC's and ICNU's arguments erroneously confuse cost allocation with rate design, misapprehending that rate design of any preference customer rate cannot result in any preference rate greater than the IP rate. The confusion is best explained by reference to section 7(e) of the Northwest Power Act and its legislative history. Section 7(e) provides: "Nothing in this Act prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or other rate forms." 16 U.S.C. § 839e(e). The legislative history of this provision clearly enunciates that section 7(e) distinguishes customer class cost allocation from rate design:

> Section 7(e) clarifies that BPA may continue, as it does under existing law, to charge uniform rates for the sale of electric peaking capacity. <u>This subsection also clarifies that the rate directives contained in this bill only govern the amount of money BPA is to collect from each class of customer and not the form of the rate used to collect that sum of money.</u> For example, time-of-day rates, seasonal rates, rate structures designed to give BPA customers particular price signals, and other rate forms would be permissible."

H. Rep. No. 96-976, 2d Sess., Pt. 2 at 53 (1980). *See also* H. Rep. No. 96-976, 2d Sess., Pt. 1 at 69 (1980) ("Section 7(e) clarifies that the Administrator may establish a uniform rate for the sale of peaking capacity and that the rate directives of this Act govern the amount of revenue the Administrator collects from each class of customers, not the rate form.").

BPA established its Tiered Rate Methodology ("TRM") and published the TRM Record of Decision ("TRM ROD") on November 10, 2008, following extensive regional discussions and a formal section 7(i) rate process. The TRM establishes a new rate design methodology for the design of preference customer (Priority Firm or "PF") rates. It is the lynchpin for BPA's long-term Regional Dialogue power sales contracts with its preference customers, with the contracts providing that the then-effective TRM "shall govern BPA's establishment, review and revision pursuant to section 7(i) of the Northwest Power Act of all rates for power sold" to the preference customers under their Regional Dialogue contracts. Regional Dialogue Contract Template, section 6.1. The

TRM constitutes a methodology only. It is not an actual rate schedule and serves as a framework for the subsequent development of tiered rates that, once adopted, would apply to sales of power under the new long-term RD contracts.

The fundamental goal of the TRM is to develop a two-tiered PF rate design that differentiates between the cost of service from the existing Federal base system (Tier 1), and the cost of power a customer is eligible to purchase beyond that amount (Tier 2). As explained in the RD Final Policy, the Tier 1 PF rate would be BPA's lowest cost-based PF rate because it would be based on the cost of BPA's existing "Federal Base System" ("FBS") resources, which are BPA's lowest cost resources, and the Tier 2 PF rate would also be a cost-based rate but would likely be higher because it would reflect, in part, BPA's costs associated with acquiring power to serve additional load growth. Both components—PF Tier 1 and PF Tier 2—would satisfy the cost recovery directives of Northwest Power Act section 7(b), governing the establishment of rates for the sale of power to preference customers. They would recover in total (i.e., "the amount of money BPA is to collect from" the preference customer rate class) only those costs properly allocable to preference customers under law. (As an aside, BPA would observe that even before tiered rates, there were significant differences in the rates charged preference customers, based on load shape, time of use, seasonality, demand factor, presence of irrigation load, conservation achievements, Slice or non-Slice election, and other factors.) As a matter of rate design regarding how to recover those costs, BPA determined that tiering the rates would send price signals that would achieve numerous significant national and regional goals, including the promotion of conservation, energy efficiency, and the development of renewable resources; maintaining low and stable preference rates; encouraging the development of regional electric infrastructure; enhancing BPA's financial stability and assurance of Treasury repayment; and providing more secure fish and wildlife funding.

With regards to DSI service, section 10.4 of the TRM is clear that "BPA might provide . . . some level of physical power under a Regional Dialogue contract" to DSIs after 2011. The TRM is also clear that

> [i]f BPA were to make such a sale, it might be necessary for BPA to purchase power to provide such service, as described in section 3.2.1.3. Notwithstanding any other provision in this TRM, all issues associated with the establishment of the Industrial Firm Power (IP) rate under section 7 of the Northwest Power Act will be determined in the applicable 7(i) process. BPA does not intend to tier the IP rate, but it is neither authorized nor prohibited from doing so by this TRM.

Id.

Consequently, BPA will establish PF rates to recover costs in total that satisfy the rate directives of Northwest Power Act section 7(b) governing preference customer rates. It will also establish IP rates to recover costs in total that satisfy the rate directives of Northwest Power Act section 7(c) governing rates for the sale of industrial firm power to

DSI customers. BPA's decision here to extend Alcoa's Initial Period in no way precludes that. Section 7(e) explicitly sanctions differing rate designs for the section 7(b) and section 7(c) rates. If the differing rate designs of those rates result in DSI rates that comply with the section 7(c) cost recovery directives, but are less than one or more of the Tier 2 rates, there is nothing in the law to preclude that and, indeed, the TRM explicitly preserves BPA's IP rate design discretion to do so.

b. Allocation of costs between Slice and Non-Slice customers

As indicated in the Alcoa ROD at 36, "[t]he Slice rate includes the $38 million average annual cost and there is no provision to alter that number through the annual Slice True-Up Adjustment Charge. Thus, no purchased power cost savings will flow to Slice customers." Nothing in this determination changes this circumstance in FY 2010 or FY 2011. However, SUB asserts that "BPA's response in the Alcoa ROD raises the question of how the risk associated with increased costs to serve Alcoa would be distributed amongst customers." EBT100007 at 8. While BPA disagrees with SUB's description of the risk as increased costs to serve Alcoa, cost and risk allocations for FY 2012 and FY 2013 will be addressed in the BP-12 rate proceeding and are not the subject of this determination.

c. Alcoa's business decision to request power at the cost-based IP rate

PPC asserts that "[u]nless BPA's analysis is missing some factors, it would appear that Alcoa is making an irrational business decision to acquire power at above market value. This behavior does not appear consistent with the actions of a sophisticated international business, and leads PPC to believe that BPA has under-estimated the value of the block of power it proposes to sell to Alcoa. EBT100010 at 2. BPA disagrees with PPC's assertion. As described in the Alcoa ROD, Alcoa has "stated that a 'mid to long term contract is desirable' and continued operations at the Intalco Plant 'need cost-based power to operate at 2 -3 lines of production to survive and plan for the future'". *See* Alcoa ROD at 7 and 8. Inasmuch as Alcoa has requested power during the Extended Initial Period and BPA's decision to grant this extension is simply an affirmative response to their request, BPA expects, all else being equal, Alcoa will take power at the cost-based IP rate as offered. As PPC knows, Alcoa has petitioned the Ninth Circuit to invalidate the EBT. BPA believes it is likely that Alcoa has done that so that it can be better assured of long-term BPA service.

d. Market price forecast is a more appropriate comparison

PPC argues, as they have previously, that "a more appropriate comparison would be to survey the market to see what type of revenues a more comparable sale would achieve. As it stands, BPA's analysis fails to demonstrate 'equivalent benefits' because it makes a fundamentally incorrect comparison." EBT100010 at 2. BPA disagrees.

As stated in the Alcoa ROD:

> BPA continues to believe that BPA believes price forecasts, in general, more accurately gauge prices that BPA will actually experience over longer periods because BPA tends to manage its inventory on a shorter term basis. Therefore, in the context of a longer-term IP sale that BPA expects to serve out of its inventory, and for purposes of valuing a transaction such as a longer-term IP sale, BPA believes it is more appropriate to rely less on the hour-to-hour, and day-to-day price fluctuations quoted in the broker market for forward delivery, and rely more on its forecast of market prices over the term of the subject contract. This is consistent with how BPA expects to serve this load and is also consistent with BPA's methodology for forecasting secondary revenues used to establish rates. (See generally WP-10-FS-BPA-03 and WP-10-FS-BPA-04.)

See Alcoa ROD at 50. The circumstances of this determination of Equivalent Benefits for the 12-month extended initial period are no different:

- BPA's tendency "to manage its inventory on a shorter term basis" remains unchanged.
- BPA still "expects to serve DSI load out of its inventory."
- BPA's approach to forecasting market prices used in this determination of Equivalent Benefits remains consistent with BPA's methodology for forecasting secondary revenues used to establish rates.

As such, BPA continues to believe, as stated above, that "it is more appropriate to rely less on the hour-to-hour, and day-to-day price fluctuations quoted in the broker market for forward delivery, and rely more on its forecast of market prices over the term of the subject contract."

PPC's argument continues undeterred, saying that BPA "should provide analysis showing that such a sale to Alcoa provides better value to the agency than a similar sale to other entities would produce." EBT100010 at 3. As was discussed at length in the Alcoa ROD, "BPA does not believe there is any support, in either its enabling statutes or Ninth Circuit precedent, for the proposition that it may make an IP sale to a DSI customer only in the event there is no higher revenue alternative sale available."[24] *See* Alcoa ROD at 53.

e. BPA's use of critical water planning

PNGC argues that:

> BPA again departs from its reliance on critical water planning and assumes that 'under most water conditions' BPA will not have to 'make purchases specifically to serve Alcoa' during the Extended Initial Period.

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[24] *See also*, *Aluminum Company of America v. BPA*, 903 F.2d 585 (9th Cir. 1990) (holding that BPA is not obligated to establish rates to maximize revenues).

> This implicates both issues of the propriety of abandoning reliance on critical water planning in connection with a decision to contract to sell firm power and BPA's longstanding contention that it makes purchases to augment its inventory, not for a particular customer.

EBT100011 at 2. BPA is not planning to abandon critical water planning for the Extended Initial Period, and BPA has already stated that it will not here visit or re-visit PNGC's claims about what BPA "knew or should have known" at the time of the December 21, 2009 determination in the Alcoa ROD. As stated in the Alcoa ROD, "BPA has set a portion of its rates for FY 2010 and FY2011 based on 1937-Critical Water Conditions as evidenced by Tables 2.3.1 and 2.3.2" entitled Loads and Resources – Federal System and "another portion of BPA's rates, notably the Secondary Sales and Purchases, for FY2010 and FY2011 were set based on average water."[25] *See* Alcoa ROD at 34. BPA expects to continue these practices for the foreseeable future.

As described further above, even though BPA projects no need to do so during the Extended Initial Period of the Block Contract, the Court recognized in separate opinions that BPA may make market purchases to support DSI sales and that BPA "is entitled to charge preference customers a rate that reflects the total cost of all FBS resources, including resources acquired to replace losses in the generation capabilities of BPA's primary resources." *See also* Alcoa ROD at 15-16 (citing *PNGC II*, F.3d at 819; *Golden Nw. Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037, 1044 (9th Cir. 2007)).

f. Curtailment Costs Related to Transmission

SUB summarized in its comments that BPA can incur curtailment costs related to transmission from this transaction, based on SUB's question and BPA's response in the Alcoa ROD. *See* SUB, EBT100007 at 4-5. SUB's question was "Does BPA's transmission inventory to provide long term ***firm*** service allow BPA to redirect the POIs to non-federal points of integration such as Mid-C to provide long term ***firm*** transmission and power service to the DSIs at no additional transmission or ancillary services costs under all power supply conditions?" *Id.* at 5. BPA's response in the Alcoa ROD was: "When BPA uses its contractual right to supply power to Alcoa at non-federal points of integration, BPA does face the risk that Alcoa may incur some congestion costs due to curtailment of [Alcoa's] redirected transmission. BPA has not yet faced a situation where it needed to pay congestion costs due to curtailed non-firm transmission and does not expect to face this condition more than a few hours per year." Alcoa ROD at 68.

BPA's response in the Alcoa ROD was not entirely responsive to SUB's original question, given that SUB specifically referred only to ***firm*** service. The response to the original question should have been that redirecting ***firm*** transmission does not change the transmission or ancillary services cost.

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[25] Tables 2.3.1 and 2.3.2 are found in WP-10-FS-BPA-01A at 10-13. Tables 4.6.2, 4.8.1 and 4.8.2 are found in WP-10-FS-BPA-05A at 77, 88-89.

PPC also commented that it is both “troubling and inconsistent” for BPA to count a “demand shift” to be a benefit, while at the same time not recognizing the costs imposed on it and its customers from transmission problems that are caused by high loads at the Alcoa Intalco Plant. EBT100010 at 3. As indicated in the Alcoa ROD, BPA currently manages PSANI congestion through curtailment protocols which result in no direct financial cost to BPA and hence congestion does not affect BPA’s EBT analysis. Alcoa ROD at 71. BPA does not consider direct costs to other parties in the EBT. The test is designed to evaluate the impact to BPA only. Even if BPA were to consider impacts to individual utilities it would be difficult to balance the positive impacts a curtailment at the Intalco Plant has on some utilities, against the negative impacts a curtailment at the Intalco Plant would have on other utilities due to constraints caused by increased or changed power flows throughout the Balancing Authority possibly resulting from a shut down of the Alcoa load.

g. Gas Price Forecast

As described below, BPA’s forecast of natural gas prices is based on sound analytics and reflects a reasonable approach and methodology. The gas price forecast component of BPA’s electricity price forecast is important because natural gas price movements contribute to price movements in electric power markets in the Pacific Northwest, because a preponderance of the generating resources establishing marginal prices for electric power are fueled by natural gas. BPA’s natural gas price forecast used in the WP-10 rate proceeding, the methodology for its development and its use as an input to BPA’s electricity price forecasts, are outlined in section 3.3 of the Market Price Forecast Study. *See* WP-10-FS-BPA-03, beginning on p. 11. This natural gas price forecast was completed by BPA in May 2009, during BPA’s third quarter of its fiscal year.

To analyze the Extended Initial Period, BPA used the most recent published natural gas price forecast it had developed using the same methodology. BPA updated its natural gas forecast with the natural gas price forecast used in BPA’s final Resource Program released September 2010. With the exception of the fiscal first quarter, BPA typically updates its natural gas and electricity price forecasts during each quarter to support financial reports.

BPA’s understanding of natural gas market fundamentals during the fiscal fourth quarter led BPA to lower its forecast of spot market natural gas prices at the Henry Hub in 2010-2011, and maintain an increase in its forecast in 2012. BPA stated in the final Resource Program:

> The effects of the economic recovery on short-term natural gas prices will be magnified by the cyclical nature of natural gas prices. An economic recession will first lower natural gas demand and therefore increase natural gas storage inventories. This will lower natural gas prices and lead to a decline in natural gas production. Typically, declines in natural gas production occur with declines in natural gas demand, but the production decline lags the decline in demand. The result is that when the economy

> and natural gas demand recovers, the recovery will occur during the downturn in natural gas production, and the natural gas price increase is magnified.

2010 Resource Program, Appendix B: Market Uncertainties, Bonneville Power Administration, September 2010, at B-3, B-4.

BPA's fiscal fourth quarter natural gas price forecast also continues to reflect a more contemporary understanding of natural gas market fundamentals. The primary reasons for BPA's reductions in 2010-2011 remain apparent in the progression of time since the natural gas price forecast was constructed. These are: a) continued strength of natural gas production, despite steep reductions in rig counts since late 2008, b) continued slow recovery of natural gas demand – particularly on the industrial side – continues to reflect the lingering effects of "an economic recession that will first lower natural gas demand," and c) near-record amount of natural gas in storage continues to demonstrate the anticipated "increase in natural gas storage inventories" contemplated in the final Resource Program.[26] Furthermore, with the majority of the hurricane season now over with no impacts on supply, the reduction made in the fiscal fourth quarter natural gas price forecast remains warranted.

BPA has also recently compared its latest forecasts of spot market natural gas prices at the Henry Hub to the forecasts produced by other forecasters in the industry. The comparison, shown in Figure 1, includes both a history of the Henry Hub spot prices – as opposed to the more frequently referenced NYMEX (now CME Group) forward market for Henry Hub natural gas prices – and other forecasters' views of the future. The forecasters typically included in our comparisons are: Bentek Energy LLC (Bentek), Cambridge Energy Research Associates (CERA), the United States Department of Energy's Energy Information Administration (EIA), PIRA Energy Group, and Wood Mackenzie.[27] The historical observations reflect the monthly average of the daily spot market prices for natural gas at the Henry Hub quoted on the Intercontinental Exchange (ICE) for the months from December 2009 through September 2010.

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[26] In addition, BPA has detailed, with contemporary information from the Energy Information Administration in Attachment B ("Natural Gas Statistics"), the continued strength of natural gas production despite steep declines in rigs, the continued slow recovery of natural gas demand (in that growth in natural gas demand is slower than growth in natural gas production), and the near record amount of natural gas in storage. See also Short-Term Energy Outlooks from the EIA for September showing the EIA lowered its forecast Henry Hub Spot Price average for 2011 to $4.76 per MMbtu, *Short-term Energy Outlook*, DOE EIA, September 8, 2010, at 6. SUB notes in its comments that the EIA released a Short-Term Energy Outlook in October that indicated that price expectations for 2011 are 4% below what they were in September.

[27] With the exception of the EIA, each of these forecasters considers their information to be proprietary. The vintage of each forecast is late April to early August 2010. EIA forecast is from their *Short-term Energy Outlook* released September 8, 2010. As noted in the prior footnote, the EIA's next *Short-term Energy Outlook* was released on October 13, 2010.

Figure 1: Henry Hub Natural Gas Spot Price Forecast

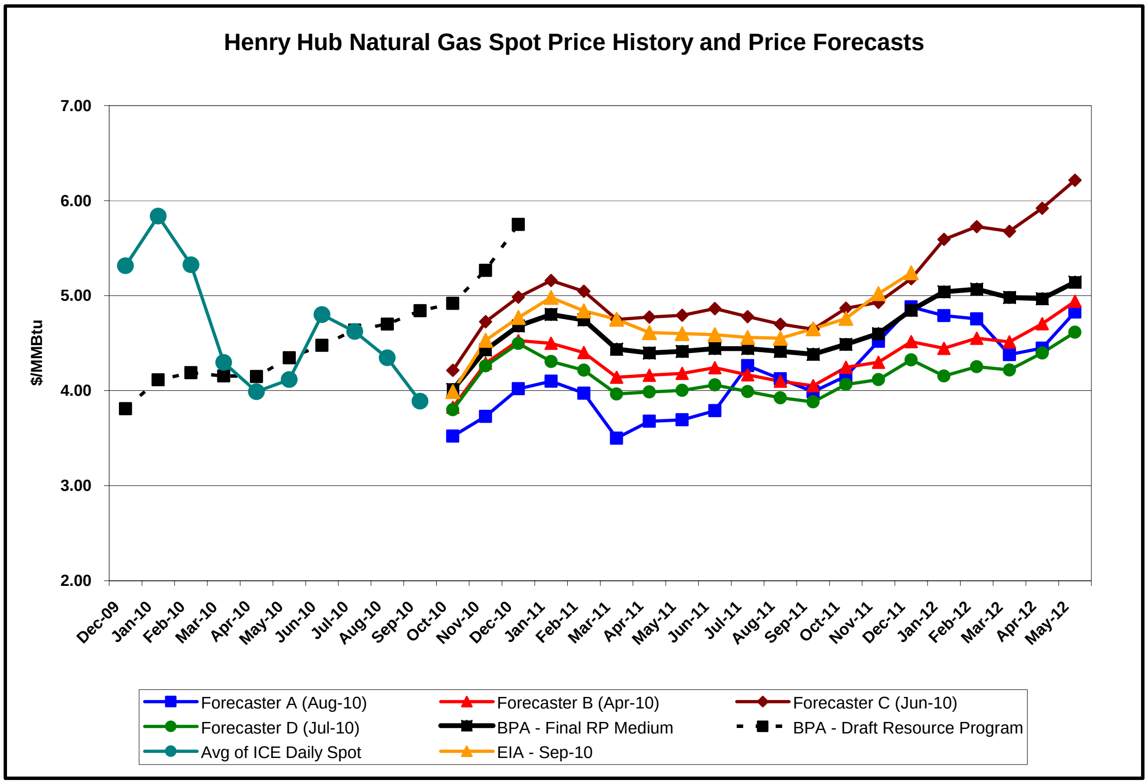


Figure 1 demonstrates that recent spot market prices for natural gas at the Henry Hub have been less than $5 per MMBtu from March 2010 through September 2010. This illustration also demonstrates that the forecasts of five other industry experts are between $3.69 per MMBtu and $4.79 per MMBtu for May 2011 – the starting month of BPA's evaluation of Equivalent Benefits for the Extended Initial Period – and their forecasts remain lower than $5 per MMBtu through at least November 2011 the month in which the EIA forecasts that Henry Hub spot prices for natural gas will average $5.02 per MMBtu. BPA's updated forecast of spot prices for natural gas at the Henry Hub is consistent with the views reflected by these five industry experts. Only two of the five forecasters expect monthly average spot prices for natural gas at the Henry Hub to rise above $5 per MMBtu during the winter of 2010-2011 in their most recent forecast. As a result, BPA believes its medium case natural gas price forecast from the final Resource Program is reasonable, and may be considered conservative, compared to a recent history of monthly average Henry Hub spot prices for natural gas and compared to what other industry experts are expecting. As stated earlier, it is also not unreasonable to assume that BPA's forecast of natural gas prices for the BP-12 rate proceeding could decline further given market developments since July, when the gas price forecast for the final Resource Program was completed.

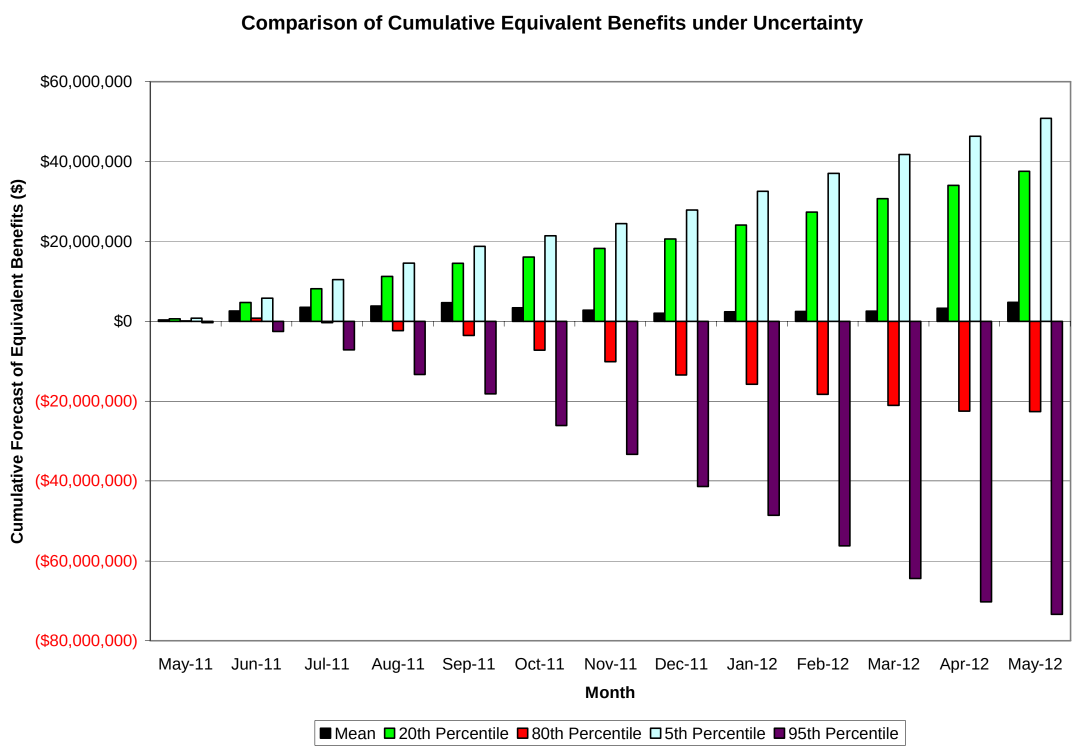
h. Risks are addressed in BPA's Equivalent Benefits Test

While BPA's analysis released in October appears to indicate that costs associated with the Block contract have been less than previously forecast for a portion of the Initial Period, SUB argues that "doesn't mean that BPA didn't put the region at risk." (SUB, EBT10001, at 6.) (BPA repeats its earlier affirmance in this ROD that it is not relying on that analysis for this EBT determination.) Consistent with the Alcoa ROD, BPA continues to believe there are two primary elements of risk in this determination to extend the Initial Period of the Block Contract. First, is the risk of market prices for electricity deviating from the prices forecast by BPA during the Extended Initial Period. The second primary element of risk is the possibility of Alcoa curtailing during the period of the extension. These risks are addressed further below and BPA believes its risks, of which the Block contract is a part, are prudently managed through BPA's operational conduct and rate proceedings. (*See generally* Risk Analysis and Mitigation Study and Documentation, WP-10-FS-BPA-04 and 04A)

Market Price Risk

BPA examined the Extended Initial Period both in isolation and more broadly in consideration of BPA's other risk factors. In examining the Extended Initial Period and the effects on the EBT in isolation, BPA applied the full probability distribution of market prices associated with its market price forecast to arrive at the net benefits for specific percentiles in that distribution.

Figure 2: Comparison of Cumulative Equivalent Benefits under Uncertainty



If market prices for electricity are less than expected, BPA is better off financially serving Alcoa during the Extended Initial Period than selling this power on the wholesale electricity market. This is reflected in Figure 2 for the 5th and 20th percentiles. Conversely, if market prices for electricity are higher than expected during the Extended Initial Period, the outcome of this EBT changes such that BPA would be relatively worse off by extending the contract with Alcoa relative to a market sale. This is reflected in Figure 2 above for the 80th and 95th percentiles. These results in isolation, however, do not reflect the impact of this transaction on BPA's overall probability distribution of net revenues, which among other things, takes into account conditions in which a loss from a DSI sale under higher prices than forecast is associated with higher surplus energy revenues for other surplus power sales.

Regarding the financial risk that market prices deviate from the average of BPA's price forecast more broadly, BPA analyzed the probability distribution of its net revenue risk consistent with the methodology used in the WP-10 rate proceeding. *See* WP-10-FS-BPA-04 at 34 and WP-10-FS-BPA-04B at 82. The advantage of this broader approach is that it takes into consideration the net revenue impacts to BPA in conjunction with all the other Operating and Non-Operating Risk Factors addressed in the WP-10 rate proceeding. *See generally* WP-10-FS-BPA-04. Our conclusion is unchanged from the Alcoa ROD in that the probability distributions of BPA's net revenues, one of its broadest measures of financial impact, are not materially different whether it serves 340 aMW of DSI load or does not serve any DSI load during the Extended Initial Period.[28]

Curtailment Risk

Regarding the risk of curtailment, the net revenue risk analyses above indicate that BPA's financial risk exposure is not materially different depending on whether or not Alcoa's Intalco Plant operates in the Extended Initial Period. As assumed in the Alcoa ROD, BPA does not expect Alcoa will curtail the Intalco Plant once 320 aMW of service is made available to it at the IP rate, which is provided during all periods under the Block Contract including the Extended Initial Period, because Alcoa has consistently believed that a seven year contract is sufficient to "permit the Intalco [Plant] to survive through this difficult recession" and "will permit the Intalco smelter to survive."[29] However, if Alcoa did shut the Intalco plant down during the Extended Initial Period, BPA does not expect, on a forecast basis, that this will have either a positive or negative impact on the Equivalent Benefits that BPA has determined above. This is because the correlation between aluminum prices set on the international market and Pacific Northwest electricity prices set regionally was computed to be very weak (.0826), based on historical data from January of 1997 through October of 2009, and very inconsistent over different time-contiguous subsets over this period of time.[30]

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[28] *See* Alcoa ROD at 62.

[29] *See* Alcoa's December 15th letter requesting 320 aMW of firm power attached to the Alcoa ROD, Alcoa in DSL090057 at 5, and Alcoa in DCA090233 at 1, submitted comments for Alcoa ROD released December 22, 2009.

For the foregoing reasons, BPA believes it has adequately addressed the risks associated with the Extended Initial Period. BPA has prudently accounted for, and expects to continue prudently accounting for, actual costs and risks associated with DSI service in setting its rates and has determined that it can reasonably expect to achieve Equivalent Benefits from this extension.

VI. ENVIRONMENTAL EFFECTS

BPA's review of the Block Contract with Alcoa for potential environmental effects that could result from its implementation, consistent with the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321 et seq, included review not just of the Initial Period but the Extended Initial Period, Transition Period, and Second Period, in the event any of these subsequent periods occur. Based on that review, BPA analysis indicates that the Block Contract falls within a class of actions excluded from further NEPA review pursuant to U.S. Department of Energy NEPA regulations, which are applicable to BPA.[31] More specifically, the Block Contract falls within Categorical Exclusion B4.1, found at 10 CFR 1021, Subpart D, Appendix B, which provides for the categorical exclusion from NEPA of actions involving "[e]stablishment and implementation of contracts, marketing plans, policies, allocation plans, or acquisition of excess electric power that does not involve: (1) the integration of a new generation resource, (2) physical changes in the transmission system beyond the previously developed facility area, unless the changes are themselves categorically excluded, or (3) changes in the normal operating limits of generation resources." Because BPA expects to provide service under the Extended Initial Period largely in the same manner and from the same types of sources as under the Initial Period, the Block Contract continues to fall within Categorical Exclusion B4.1. The December 14, 2009 Environmental Clearance Memorandum that documents this categorical exclusion for the Block Contract is posted at BPA's website at: http://www.efw.bpa.gov/environmental_services/categoricalexclusions.aspx.

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[30] *See* Alcoa ROD, section e(4)(ii)5.

[31] *See* Alcoa ROD, section IX beginning at 107.

VII. CONCLUSION

Based on the above application of the EBT, BPA has determined that it can grant Alcoa's request to provide an Extended Initial Period of the Block Contract with Alcoa. The Extended Initial Period will begin on May 27, 2011, and end on May 26, 2012.

Issued at Portland, Oregon, this 29th day of October, 2010.

___/s/ Stephen J. Wright________________
Stephen J. Wright
Administrator and Chief Executive Officer

ATTACHMENT 3

arguments are misplaced. The IP rate is the statutorily prescribed rate under section 7(c). Part of the rate directive requires providing a credit for the value of the reserves provided by the DSIs. There is nothing in the statute to suggest that the value of reserves credit should be used by BPA to manipulate the base IP rate (essentially the PF rate plus the typical margin less the value of reserves) because of the perception of some parties that the IP rate is below the competitive market prices that the DSIs would pay if they were not paying the rate that is statutorily mandated. Such circumvention of congressional intent would clearly be unacceptable.

As for other assertions in the Brief on Exceptions, those have been adequately addressed already. It is true that many of the reasons adopted in 1996 for abandoning the "share the savings" approach are not as compelling today. *Id*. at 21. The simple facts, and those that are the most compelling, remain unchanged. The "share the savings approach" is an artifact of a bygone era for which no party to this proceeding has provided a statutory basis. Without such a basis, there is no sound reason to continue a practice which basically deprives the DSIs of half the value of the reserve product provided pursuant to their statutory obligation.

Decision

BPA will continue to adopt the policy established in 1996 and will compensate the DSIs for the full value of provided reserves.

14.9 Section 7(c)(2) Typical Margin

Issue 1

Whether the level of the 2007 typical margin should be adjusted by an inflation factor.

Parties' Positions

PPC *et al.* argue that BPA has not offered any rational justification for why BPA should not adjust the last typical margin for inflation. PPC *et al.*, WP-10-B-JP11-01, at 12. PPC *et al.* state that doing so would align BPA's typical margin determination with normal ratemaking practice, which assumes inflationary increases for future costs, and would likely result in BPA's determination of the typical margin being based on substantial evidence. *Id*. PPC *et al.* state that adjusting the typical margin from four years ago by inflation would support the conclusion that the typical margin represents what is typically charged by preference utilities. *Id*.

Alcoa argues that BPA should reject the adjustment to the typical margin and retain the $0.57/MWh margin that was supported by substantial evidence. Alcoa Br. Ex., WP-10-R-AL-01, at 2. Alcoa first argues that increasing the typical margin for inflation fails to meet the statutory standard for calculating the typical margin. *Id*. at 2-4. Alcoa then argues that such a change is not based on "substantial evidence in the rulemaking record." *Id*. at 4-5. Alcoa argues that the proposition that the typical margin increases with inflation is not based on any evidence other than speculation. *Id*. at 5-6. Finally, Alcoa argues that should BPA adopt such an adjustment, it fails to place the burden of proof on the rate case participants who are in the best position to bear it. *Id*. at 6-8.

BPA Staff's Position

Given the essentially unprecedented economic conditions that exist at the present time, it would be difficult to make an informed decision regarding whether the typical margin should be inflated or deflated. Fisher *et al.*, WP-10-E-BPA-36, at 24-26. In addition, changes in the typical margin over the period since 1996 have been rather small, and Staff would expect any changes in the typical margin, up or down, since 2005 (the year in which the data was collected for the most recent typical margin study) to be similarly small. *Id*. at 26. Staff disagrees with parties' recommendation that the 2007 typical margin should be adjusted by an inflation factor. *Id*.

Evaluation of Positions

In their direct testimony, both PNGC and PPC *et al.* state that the 2007 typical margin proposed in this rate case is outdated and understates the size of the typical margin. Prescott *et al.*, WP-10-E-PN-01, at 5-7; O'Meara *et al.*, WP-10-E-JP7-1, at 5. These parties recommend that BPA should have either re-performed the typical margin study or adjusted the 2007 typical margin by an inflation factor. Prescott *et al.*, WP-10-E-PN-01, at 5-7; O'Meara *et al.*, WP-10-E-JP7-01, at 5.

After further consideration of this issue, and review of the arguments presented by PPC *et al.*, BPA concludes that, despite Staff's concern with the difficulty of predicting the direction of change due to unprecedented economic conditions, this factor is outweighed by BPA's desire to remain aligned with normal ratemaking practice, which assumes inflationary increases for future costs.

Furthermore, doing so would be consistent with BPA's practice in the 1980s when the IP-PF link was used in establishing the IP rate. The IP-PF link contained an inflation adjustment based on the latest available GNP implicit price deflator. The purpose of the inflation adjustment was to conform the currently effective rate link to price levels in future test periods. Diffely, BPA, IP-PF-86-E-BPA-01, at 9. BPA agrees with PNGC and PPC *et al.* that, due to the number of years that have elapsed since BPA last conducted a typical margin study, inflationary forces would most likely have caused an increase in the types of overhead costs included in the typical margin.

Prior to this WP-10 rate proceeding, BPA was unable to dedicate time and staff to conducting a new typical margin study. The combination of the WP-07 Supplemental proceeding ending in September and the timing of the *PNGC* opinion in December left no time for such an undertaking, which would have required extensive coordination with PPC in collecting the data and significant time and energy in reviewing the data for purposes of calculating the typical margin. PPC itself was fully involved in the WP-07 Supplemental proceeding. The fact that a new study was not feasible, however, does not relieve the Administrator of his duty to review the typical margin and to ensure that it is consistent with the statutory command that it be "equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." 16 U.S.C § 839e(c)(1)(B)

It is reasonable to conclude that the industrial consumers of preference customers have experienced inflationary forces since the last typical margin study. It is also reasonable to conclude that such forces would affect such customers over a broad spectrum of costs, including costs associated with the typical margin. Finally, it is reasonable to conclude that using an appropriate adjustment mechanism will provide a reasonably accurate means of accounting for such increased costs without the substantial investment of time and resources needed to conduct a new typical margin study *de novo*. Adjusting the typical margin by an inflation factor causes a very modest increase in the IP rate, but such an adjustment is necessitated by the statutory requirement that the typical margin be equitable when compared to the margins paid by regional industrial consumers of preference utilities. As noted by PPC *et al.*, this approach is also consistent with generally accepted ratemaking principles, which presume increased future costs due to inflationary forces. Thus, the typical margin from the WP-07 rate case will be adjusted for inflation, aligning BPA's typical margin determination with normal ratemaking practice and statutory requirements governing development of the IP rate.

In its Brief on Exceptions, Alcoa has raised a number of objections to the draft decision. First, Alcoa argues that an adjustment for inflation is inconsistent with section 7(c)(2) of the Northwest Power Act, which lists a number of factors to be considered by the Administrator in developing the IP rate, including 1) the comparative size and character of the loads served, 2) the relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions, and 3) direct and indirect overhead costs; all as related to the delivery of power to industrial consumers. Alcoa Br. Ex., WP-10-R-AL-01 at 2-3, *citing* 16 U.S.C. § 839(c)(2). Alcoa argues that the test is not discretionary and that BPA has failed to meet the legal standard for determination of the typical margin, primarily because there is no evidence in the record that the margins to industrial consumers of publicly owned utilities have been increased since the typical margin was last developed by BPA based on the actual survey of margins to industries. *Id.* at 2.

Alcoa then goes on to cite some of the testimony that does bear on the issue of whether there should be an adjustment for inflation: Prescott *et al.*, WP-10-E-PN-01, at 5-7; O'Meara *et al.*, WP-10-E-JP7-01, at 6-7. Thus, by Alcoa's own admission, the record is not devoid of testimony related to this issue. Other parties have essentially pointed out that it has been a number of years since BPA has updated its data; that preference customers have, like everyone else, experienced inflation during that period; and that it would be reasonable at least to update the typical margin to account for that inflation. It is unclear why Alcoa believes such common sense observations are not "competent" for the purposes of this hearing. Alcoa Br. Ex., WP-10-R-AL-01, at 3. BPA does not believe that some sort of economic study is indicated for the purpose of showing that inflation has occurred. The real question is whether inflation has affected the typical margin and, if so, what standard should be used to account for such effect in the absence of a specific study. For such purpose, there is substantial record evidence to conclude that an adjustment should be made based on the GNP implicit price deflator.

Neither is BPA's decision to include an inflation adjustment deficient because it fails to take account of every criterion listed in section 7(c)(2). All such criteria were considered the last time BPA conducted a typical margin study. To that extent, such criteria are still embedded in the typical margin calculation. The only difference is that, in the absence of an updated study, BPA has decided to take account of inflation, which certainly qualifies as an "indirect cost" under section 7(c)(2). The Administrator's decision, then, is consistent with statutory directives.

Alcoa then goes on to suggest that ICNU acted improperly by not providing information relevant to the typical margin calculation in response to Alcoa's data request, stating that ICNU refused Alcoa's data request for actual evidence of any data supporting such assertions of increases in typical margins. *Id*. at 4. This allegation is misleading at best. Alcoa itself notes that its data request would have required "the power bills of ICNU's members in order to verify its flimsy evidence." *Id*. at 7, *citing* Response to Data Request No. AL-JP7-3. ICNU objected to the request and, subject to that objection, stated that it had no documents responsive to the request. Alcoa did not file a motion to compel and, by failing to do so, essentially acquiesced to ICNU's response. Moreover, even if the requested information had been produced, it is not clear to BPA how power bills would aid in calculating the typical margin. When conducting a margin survey, BPA routinely relies primarily on COSAs, or COSA-like information, from preference utilities to determine which costs are allocable to the typical margin and which are not. Utility bills would not provide this type of information.

Alcoa then attacks the inflation adjustment as not being based on substantial evidence. *Id*. at 4. Alcoa argues that BPA may not "assume inflationary increases" in the absence of substantial evidence in the rulemaking record considered as a whole that allows the Administrator to make a "determination" in applying the specific statutory standards in section 7(c)(2) of the Northwest Power Act. *Id*. at 5. Alcoa maintains that such an assumption about inflation does not meet that standard. *Id*. Alcoa's proposed standards for making this determination go well beyond the straightforward unembellished definition of "substantial evidence" proffered by PPC *et al.* in their Initial Brief: the "substantial evidence" standard requires that the Administrator's decision be based on "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion." PPC *et al.* Br., WP-10-B-JP11-01, at 11, *citing Consolidated Edison Co. v. NLRB*, 305 U.S. 197, 229 (1938).

Thus, the standard is a flexible one, requiring issue-by-issue application, not the straightjacket that Alcoa seems to impose. The question in this instance is whether it would be reasonable, based on the testimony in the record, to conclude that, during the period since the last typical margin study was conducted, inflation has affected the margins of retail industrial consumers. The answer is "yes." Would it be reasonable for the Administrator, therefore, to conclude that an inflation adjustment is consistent with his consideration of "indirect costs" pursuant to section 7(c)(2) and his obligation to establish a typical margin that is "equitable in relation to" the margins experienced by the industrial consumers of preference utilities? Again, the answer is "yes."

As Alcoa notes, Staff struggled with this issue, declining to include an inflation adjustment. Alcoa Br. Ex., WP-10-R-AL-01, at 5-6. Staff's concerns largely centered on the present downturn in the economy and the difficulty of determining, in such an environment, whether the current trend is inflationary or deflationary, and whether utilities would pass increased costs on to their retail industrial consumers. Ultimately, however, BPA considered the fact that the majority of the time that has elapsed since the last typical margin study was conducted occurred during more economically robust times, and so, on balance, it would be reasonable to rely on the

GNP deflator as a surrogate for the absence of an updated study. Taking that into account, BPA adopts PPC *et al.*'s position but rejects PNGC's testimony, Prescott *et al.*, WP-10-E-PN-01, at 6-7, that BPA adopt the Handy-Whitman Index of Public Utility Construction Costs. The Handy-Whitman Index would be a less-accurate measure of inflationary forces on the types of costs associated with the typical margin. Fisher *et al.*, WP-10-E-BPA-36, at 25-26.

Instead, BPA determines that it will rely on the GNP implicit price deflator index. In large part, this decision is based on BPA's reliance on that mechanism as a vehicle for adjusting the typical margin and the value of reserves credit in the past. 1986 IP-PF Rate Link ROD, IP-PF-86-A-02. At that time, the Administrator made the following determination:

> The GNP implicit price deflators are estimates of the amount of annual inf1ation forecasted to occur throughout the economy. They frequently are used to adjust for inflation effects when making cost comparisons between different years. Use of the GNP implicit price deflators is consistent with the escalation rates generally used for the program estimates in BPA's rate proposals. The GNP deflator index is preferable to other inflation measures for the purpose of the IP-PF rate link because it is easy to use and is readily available. Further, it is a generally accepted measure of inflation over time.

Id. at 8, *citing* Diffely, IP-PF-E-BPA-01, at 12.

The Administrator went on to describe the purpose of using the GNP implicit price deflator instead of performing a typical margin study during the approximately 10 years that the IP-PF link was in effect:

> BPA is establishing the IP-PF rate 1ink as a long-term ratemaking methodology to achieve greater load planning certainty by providing the DSIs with improved rate predictability and to reduce the controversy and need for data collection in future BPA rate cases.

Id. at 9, *citing* Diffely, IP-PF-E-BPA-01, at 2-4. Thus, BPA's rationale for adjusting the typical margin based on the GNP implicit price deflator has equal force today. Due to the difficulty in collecting data for a complete typical margin study, the deflator serves as an acceptable surrogate. It should be noted that, at that time, the DSIs supported BPA's use of the GNP deflator. *Id*.

Finally, Alcoa argues that BPA's draft decision is defective because BPA has failed to place the burden of proof on those who are seeking the adjustment. Alcoa Br. Ex., WP-10-R-AL-01, at 6-8. Essentially, Alcoa argues that the preference customers and their industrial consumers are in possession of the information that would allow BPA to conduct a typical margin study, and so the burden of proof should be on them to show that an inflation adjustment is necessary. *Id*. As indicated above, BPA believes that the inflation adjustment comports with all legal requirements. However, the peccancy for failing to conduct a new typical margin study falls on BPA, not on the preference customers and their industrial consumers. Thus, the consequences of any decision not to obtain information needed to conduct a typical margin study rests with BPA. In such a situation, the Administrator will not impose any additional evidentiary burdens on the parties advocating an inflation adjustment. Such a determination would be the equally heavyhanded equivalent of declaring that Alcoa is judicially estopped from objecting to use of the GNP deflator now on the basis that the DSIs previously supported use of the deflator, as noted above, in 1987 during the IP-PF Link proceedings.

Therefore, the typical margin used in the WP-07 rate case will be adjusted for inflation, thus aligning BPA's typical margin determinati., the PF preference rate) and the "typical margins" that are to be included in the IP rate.

Decision

BPA will adjust its most recent typical margin by an inflation factor, using the GDP Implicit Price Deflator. Accordingly, the typical margin used in calculating the IP rate for this rate case is 0.63 mills/kWh.

Issue 2

Whether revenue taxes should be included in the typical margin.

Parties' Position

PPC *et al.* argue that BPA should include revenue taxes in the typical margin. PPC *et al.* Br., WP-10-B-JP11-01, at 12.

BPA Staff Position

BPA should retain the policy established in 1996 and not include revenue taxes in the typical margin. Fisher *et al.*, WP-10-E-BPA-36, at 27.

Evaluation of Positions

PPC *et al.* argue that BPA's typical margin should include Washington state revenue taxes, because these taxes are included in the margins charged by Washington public utilities to their industrial consumers, and the majority of publics' load, as well as DSI load, is in the state of Washington. PPC *et al.* Br., WP-10-B-JP11-01, at 12. PPC *et al.* argue that BPA's methodology for establishing the typical margin is overly simplistic and fails to take into account the purpose of the typical margin. *Id.* at 13. That purpose, according to PPC *et al.*, is to establish an adder to the DSIs' rates so that their rates have a "relation to the retail rates charged by the public body and cooperative customers" to their industrial consumers. *Id.*, *citing* 16 U.S.C. § 839e(c)(1)(B). PPC *et al.* state that the typical margin should, therefore, be a margin charged to the DSIs that represents the margins the DSIs might have paid as industrial consumers of preference customers. PPC *et al.* Br., WP-10-B-JP11-01, at 12. Therefore, PPC *et al.* conclude, the location of the DSIs and the typical margins that are charged in that state could and should be a relevant factor in determining the appropriate typical margin to add to the DSIs' rates. *Id.*

Since 1996, BPA has concluded that revenue taxes are not typical, as intended by the statutory directive that requires that the BPA rate applicable to DSI sales "shall be based upon the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates." WP-10-E-BPA-36 at 27, *citing* 16 U.S.C. § 839e(c)(2); WP-96 Wholesale Power Rate ROD, WP-96-A-02, at 180.

PPC *et al.* misconstrue the statutory directive for determining the typical margin that applies to the IP rate. Section 7(c)(1)(B) of the Northwest Power Act provides that the rate for service to DSIs for the period beginning July 1, 1985, shall be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers *in the region*." 16 U.S.C. § 839e(c)(1)(B). Thus, the statute makes clear from the outset that the rate determination should be based on a regional view of equitability, not one that is state-specific. The statute goes on to say, more specifically, that "[t]he determination under paragraph (1)(B) of this subsection shall be based upon the Administrator's applicable wholesale rate to such public body and cooperative customers and the typical margins included by such public body and cooperative customer in their retail industrial rates." 16 U.S.C. § 839e(c)(2).

Thus, the explicit language of the statute makes it clear that, when BPA calculates the "typical margin," it must assess the "typical margins" that are charged by all of BPA's public body and cooperative customers to their industrial consumers, not some select group. The location of the DSI facilities themselves is not mentioned in the statute. Thus, it is reasonable to conclude that Congress's command to create an IP rate that is "equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers *in the region*" applies both to the applicable wholesale rate (*i.e.*, the PF preference rate) and the "typical margins" that are to be included in the IP rate.

This interpretation is consistent with BPA's practices since 1996. WP-96 ROD, at 160. There, the Administrator found as follows:

> Section 7(c)(2) provides that the determination under section 7(c)(1)(B) shall be based on BPA's applicable wholesale rates to its public body and cooperative customers "and the typical margins included by such public body and cooperative customers in their retail industrial rates." *Id.*, 16 U.S.C. § 839e(c)(2). BPA asserts that revenue taxes are not a component of the typical industrial margin because a majority of BPA's preference customers with industrial [consumers] do not pay revenue taxes, and therefore the majority do not include revenue taxes in their retail industrial rates.

Id. at 160. In reaching this conclusion, BPA undertook an analysis of what is meant by a "typical" margin and based the final determination on that analysis. BPA derived the meaning of typical as follows:

> "Typical" means "representative of a whole group"; The American Heritage Dictionary of the English Language 1388 (1976); "serving as a characteristic example"; "representative." New Shorter Oxford English Dictionary 3442 (1993). If a given trait is peculiar only to a minority of a population, it cannot be said to be either "representative of [the] whole group" or "a characteristic example." If anything, the opposite is the case: the absence of the trait is representative and characteristic. Therefore, if only a minority of utilities include

> revenue taxes in their margins, then such taxes are not a component of the typical industrial margin.

Id. at 178. BPA then applied this analysis to data available in the WP-96 rate proceeding record:

> BPA has 81 public utility customers that have retail industrial loads. Chang, Cocks, [WP-96-]E-BPA-54, at 6. Of these, 34 are in Washington, and therefore are subject to revenue taxes, and 44 are located elsewhere, and therefore do not pay revenue taxes. *Id*. at 6 and Attachments A and B. (BPA was unable to determine the customer classes for three of its public body customers. All of these customers, however, are located outside of Washington, and therefore are not subject to revenue taxes. *Id*. at 7.) Moreover, as APAC indicated, revenue taxes are paid in only one of seven states served by BPA. Wolverton, [WP-96-]E-PA-01, at 11. Therefore, they are not representative of the region as a whole. *Given this evidence, it can hardly be said that the payment of revenue taxes (and their inclusion in industrial margins) is typical; to the contrary, if anything it is typical for a utility not to include revenue taxes in its margin*.

Id. (emphasis added.) BPA also concluded:

> BPA is not suggesting that a cost must be incurred by all utilities, or in every jurisdiction, to be included in the margin. Indeed, such an argument would be as unconvincing today as it was in 1985. A cost need not appear in every utility's industrial rate to be typical of the class; the statute's use of the word "typical" rather than, for example, "universal" belies this approach. When a cost appears in only a minority of utilities' industrial rates, however, and when that minority is concentrated in only one state in the region, the cost is neither universal nor typical, and should be excluded from the margin.

Id. at 185. The issue was raised again in the WP-02 rate proceeding. As noted in Staff's rebuttal testimony:

> During the 2002 rate case, BPA focused on the issue of whether revenue taxes were or were not "typical." Rate case parties introduced tax statutes from Oregon and Idaho, arguing that such taxes were the equivalent of revenue taxes; therefore, they concluded, revenue taxes were indeed typical with respect to utilities serving industrial load in BPA's service territory. In the 2002 rate case ROD, BPA responded by doing a comprehensive analysis of the statutory provisions, concluding that the taxes identified by the parties were not revenue taxes, and Washington was the only state in the region that levied a revenue tax.

Fisher *et al.*, WP-10-E-BPA-36, at 27, *citing* WP-02 Wholesale Power Rate ROD, WP-02-A-02, at 15-3 – 15-15.

At that time, parties once again challenged BPA's methodology and argued, as they had in 1996, that BPA should revert to the decision made in 1985, which included revenue taxes in the typical margin:

> The IOUs argue that BPA's witness did not make any independent analysis regarding the issue of "whether government-owned utilities and cooperatives typically pay taxes based on gross receipts from the sale of electric power and

> whether such taxes should be included in the 'typical retail margin'." *Id*. at 28; *see also* PGE Brief, WP-02-B-GE-01, at 9.

WP-02 ROD, WP-02-A-02, at 15-3.

PPC supported the IOU position, at least in part:

> PPC makes a similar argument, asserting that perhaps as many as 29 utilities in Oregon pay franchise fees and in-lieu taxes, and claiming that BPA should have investigated the issue further based on IOU testimony that "a few telephone calls" had shown that Oregon jurisdictions charge revenue taxes. PPC Brief, WP-02-B-PP-01, at 58-59, *citing* Hoff *et al.*,WP-02-E-AC/GE/IP/MP/PL/PS-03, at 19.

BPA once again rejected this line of argument and determined that revenue taxes are not includable in the typical margin:

> BPA's analysis of whether revenue taxes should be included in the margin considered both: (1) the number of utilities serving industrial load and subject to a revenue tax; and (2) the number of states within BPA's service territory which levy a revenue tax. Ebberts, WP-02-E-BPA-47, at 6. Based on those parameters, BPA concluded that, for purposes of calculating the industrial margin, only the state of Washington levies a gross revenue tax. *Id*. This means that revenue taxes are typical neither of the states within BPA's service territory nor among BPA's customers serving industrial load. *Id*. Therefore, revenue taxes are not "typical" as contemplated by section 7(c)(2) of the Northwest Power Act and should be excluded from the margin. *Id*.

WP-02 ROD, WP-02-A-02, at 15-5. In responding to the question of how many states within BPA's service territory levy a revenue tax, BPA analyzed the various taxes that parties argued were the equivalent of revenue taxes; the parties argued also that BPA should consider them as such, and should then reach the conclusion that a majority of the states in BPA's service territory levy revenue taxes.

BPA's analysis showed that the identified taxes were not revenue taxes and were thus not includable in the typical margin. First, BPA analyzed the Washington state revenue tax, concluding as follows:

> The essential features of the Washington revenue tax, then, can be described as follows: (1) it is a comprehensive tax, imposed solely for revenue purposes; (2) it is levied and administered at the state jurisdictional level; (3) it is a tax on "gross income," defined broadly; and (4) it is not a license fee, regulatory tax, or occupation tax.

Id. at 15-9. BPA then analyzed the other taxes being promoted as revenue taxes.

First, BPA examined ORS chapter 308, which the IOUs had characterized as the equivalent of a revenue tax, and found that the Oregon tax was not analogous to the Washington revenue tax:

> First, it is not a revenue tax at all, but rather a property tax. As the Supreme Court of Oregon has held:

> > ORS chapter 308 deals with valuation of various types of property for property tax purposes. ORS 308.805 through 308.820 deal with a specific type of property (electrical distribution systems) owned by a specific class of taxpayers (non-profit electric cooperatives). ORS 308.805 provides a method of taxing such property different from the usual ad valorem method based on assessed value. Although the tax is measured by gross revenue, the tax is more properly considered a property tax than an income tax.
>
> *Lane Electric Cooperative v. Department of Revenue*, 765 P.2d 1237, 1239 (1988).
>
> While the holding of the Oregon Supreme Court is not binding on the Administrator for purposes of interpreting section 7(c)(2), the description clearly comports with the statutory language, and the Administrator finds it persuasive with regard to the character of the tax. Moreover, the court's interpretation is supported by the fact that the income basis for the tax applies only if the tax owed is less than the tax would be if based on the market value of the property itself. Thus, the tax embodied in ORS chapter 308 is not a revenue tax, but a property tax. Moreover, the Oregon tax differs in other material respects from the tax imposed by the state of Washington. First, it is not a comprehensive tax at the state level; instead, it is specifically targeted at a very limited classification of taxpayers and is earmarked for use by the county for specific purposes. Second, because the funds are distributed to the county governments, the tax is not wholly administered at the state level. Third, even if it could be characterized as an income tax, the Oregon tax is not a tax on "gross income," but a tax on income derived from a specific and limited type of property. For purposes of calculating the margin, two taxes of a completely different character cannot simply be lumped together and treated as though they are the same thing.

Id. at 15-9 – 15-10.

BPA similarly found that the Idaho statute promoted by the IOUs for "revenue tax" treatment was not, in fact, a revenue tax:

> The IOUs' reliance on Idaho's statute, IC 63 3502, is similarly misplaced. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 38. That tax applies to any "Cooperative Electrical Association," defined as "any nonprofit, cooperative association organized and maintained by its members, whether incorporated or unincorporated, for the purpose of transmitting, distributing or delivering electric power to its members." IC 63 3501. The tax is computed at a rate of 3.5 percent on gross earnings after deducting that figure by its costs of power and certain Energy Northwest costs. IC 63 35 02. Moreover, payment of the tax is deemed to be inlieu of all other property taxes. Thus, it is very similar to the Oregon tax and for the same reasons, it is a property tax rather than a revenue tax. As the DSIs correctly note:
>
> > Many of the utilities that assess taxes that might be called 'revenue taxes' in reality collect taxes in lieu of property taxes. Property taxes are

> appropriately assigned to the production, transmission, and distribution categories in the margin study, depending upon the taxable property upon which they are levied. These in lieu taxes are not revenue taxes of the kind that is levied by utilities located in the State of Washington.

Id. at 15-10, *citing* DSI Brief, WP-02-B-DS-01, at 30.

BPA also analyzed franchise fees authorized under ORS §221.420, §225.270, and §225.270 and found similarly that such taxes are not revenue taxes. WP-02 ROD, WP-02-A-02, at 15-10 – 15-11.

BPA's comprehensive analysis of the tax statutes has not been challenged in this proceeding. Therefore, revenue taxes are not typical within the states that comprise BPA's service territory. Neither are they typical among BPA's preference customers who serve industrial load. Revenue taxes have to be "typical" within the entire region served by BPA, and not just a feature of a single state within the region; revenue taxes are not typical on that basis.

Thus, as stated in the 2002 ROD:

> Because BPA's conclusion regarding which jurisdictions levy revenue taxes is correct, it follows that the only factual determination necessary is whether, at a minimum, a majority of the Administrator's public agency customers serving industrial load are subject to Washington's revenue tax. BPA's witness provided this information in direct testimony and furnished updated numbers in rebuttal, *concluding that 32 utilities serving industrial load are in Washington, and 51 are located elsewhere*. Ebberts, WP-02-E-BPA-22, at 8; Ebberts, WP-02-E-BPA-47, at 7.

Id. at 15-12. This factual evidence has not been challenged in this proceeding, and BPA will continue to rely upon it.

As can readily be seen, PPC *et al.* have not established a basis for their claim that BPA's analysis is, and has been, "overly simplistic and fails to take into account the purpose of the [typical] margin." In fact, the evidence shows that BPA's analysis has been comprehensive, if not exhaustive, in addressing various arguments made in favor of inclusion of revenue taxes in the typical margin. The PPC *et al.* analysis fails to take into account the purpose of the typical margin as explicitly set forth in section 7(c) of the Northwest Power Act by relying on the assumption that the location of DSI facilities is relevant. It is not. The statute clearly provides that the rate made available to DSIs must be "equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers *in the region*."

Since 1996, BPA has adhered to that standard, and it sees no reason to reverse course.

<u>Decision</u>

Revenue taxes will not be included in the typical margin.

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing testimony on Bonneville Power Administration's Office of General Counsel and Hearing Clerk and all litigants in this proceeding by uploading the document to the 2012 Rate Adjustment Proceeding (BP-12) secure websites pursuant to BP-12-HOO-02.

DATED: January 21, 2011.

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