Attachments to

**Issues Remanded to Bonneville Power Administration in *Pacific Northwest Generating Cooperative, et al., v. Bonneville Power Administration,* 580 F.3d 792 (9th Cir. 2009) (*PNGC I*)
and *Pacific Northwest Generating Cooperative, et al., v. Bonneville Power Administration,* 596 F.3d 1065 (9th Cir. 2010) (*PNGC II*)**

ADMINISTRATOR'S DRAFT RECORD OF DECISION

June 22, 2010

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Attachment A

Letter to the Region on DSI Lookback Issue (6/10/09)

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

EXECUTIVE OFFICE

June 10, 2009

In reply refer to: A-7

To Regional Customers, Stakeholders, and Other Interested Parties:

On December 17, 2008, the United States Court of Appeals for the Ninth Circuit (the court) issued its opinion in *Pacific Northwest Generating Cooperative, et al. v. Bonneville Power Administration*, 550 F.3d 846 (9th Cir. 2008) (*PNGC*), a case involving the challenge by certain parties to Bonneville Power Administration's (BPA's) FY 2007 – 2011 direct service industrial customer (DSI) service construct and contracts.

Among other holdings, the court granted the petitions challenging BPA's statutory authority to offer the DSIs energy at rates below both the Industrial Firm (IP) power rate and the market rate. *PNGC*, at 882. Since the *PNGC* decision was issued, BPA's preference utility customers have argued that as a consequence of this holding the DSIs received more benefits during the 25-month period preceding the court's opinion (Lookback Period) than BPA was authorized by statute to provide them, and that the excess must be recovered by BPA from the DSIs. For its part, BPA's DSI customer Alcoa, Inc. (Alcoa) has argued that if BPA had applied the IP rate as required by *PNGC*, then it would have received significantly more monetary benefits during the Lookback Period and, therefore, Alcoa is entitled to recoup those additional payments.

In addressing the contention by certain preference utility petitioners that the damages waiver provision in the contracts was void and that BPA must recover overpayments from the DSIs, the court held as follows:

> The question of contractual interpretation before us is whether, if the agreements are partially invalidated, BPA is permitted to seek restitution, not whether it is 'requir[ed]' to do so. Whether BPA intended to retain the flexibility to seek *or* forgo repayment, depending on (a) the DSIs' 'commitments with respect to operating their facilities,' and (b) BPA's interest in still making sales of physical power to them, is an issue the agency did not address in the Supplemental ROD.

Id. (emphasis in original). The court then remanded to BPA "to determine in the first instance the applicability and construction of the severability clause, the damage waiver, and the physical power sale option in light of our holdings here." *Id*.

Therefore, the threshold issues before BPA on remand are whether, as a matter of law and in view of the holdings in *PNGC*,

1) BPA is permitted under the applicable contracts to seek repayment from the aluminum company DSIs Alcoa and Columbia Falls Aluminum Company (CFAC) for any overpayments of monetary benefits during the Lookback Period;

2) Alcoa is permitted to seek additional payments from BPA for the Lookback Period; and

3) BPA is permitted to seek additional payments directly from Port Townsend Paper Company (or indirectly through the Public Utility District No. 1 of Clallam County) for any undercharges for power delivered to Clallam by BPA for the benefit of Port Townsend, both during the Lookback Period and subsequently.

BPA will commence a bifurcated process to address these issues. In the first part, in early July, BPA plans to issue a draft record of decision on the remanded contract issue outlined above, *i.e.*, "the applicability and construction of the severability clause, the damage waiver, and the physical power sale option." Written comments on the draft record of decision must then be filed with BPA in early August 2009. BPA plans to issue a final record of decision regarding the remanded contract issue in late September. In the event BPA's final decision with respect to the remanded contract issue is that, as a matter of law, payments to or from BPA (Lookback Amounts) are precluded, that finding will constitute the Administrator's final decision and no further proceedings will be necessary.

However, in the event BPA's decision in the final record of decision is that the payment to or from BPA of a Lookback Amount is not precluded, then BPA will commence the second part of the process to determine whether, and in what amount, BPA or a DSI is entitled to a Lookback Amount. This second part of the bifurcated process, if necessary, will commence with a workshop, the date and time of which will be announced, if necessary, following release of the final record of decision. The purpose of the workshop will be to discuss whether parties believe it would be necessary to undertake a formal hearing in order to create a record with respect to whether, and in what amount, BPA or a DSI is entitled to a Lookback Amount, or whether such a record could be adequately created through an informal process, including one or more workshops and/or the submission of written arguments and evidence to BPA and other parties.

All parties should keep in mind that litigation is ongoing in the Ninth Circuit that could result in orders that have a bearing on the outcome of this process. The court is still reviewing its original decision pursuant to the filing of petitions for rehearing filed by Port Townsend Paper and BPA. Thus, the mandate has not yet issued and the court is free to change its opinion until that time. Also, the court is reviewing challenges to the contract amendment providing service to Alcoa through FY09. It is possible, then, that the timing of events under this process might have to be adjusted to accommodate any decisions of the court relevant to the Lookback determination.

Most importantly, BPA will not issue its final determination on the applicability of the damage waiver, severability clause, and power sale option on the date specified above if the mandate in the original *PNGC* case has not issued prior to that date. In that event, BPA will issue a notice to the parties describing BPA's intentions with regard to the adjusted timing of events that may be necessary to complete this process.

/s/ Stephen J. Wright

Stephen J. Wright
Administrator and Chief Executive Officer

Attachment B

Letter to the Region Announcing Delay to the DSI Lookback Process (7/24/09)

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

EXECUTIVE OFFICE

July 24, 2009

In reply refer to: A-7

To Regional Customers, Stakeholders, and Other Interested Parties:

On June 10, 2009, the Bonneville Power Administration (BPA) issued a letter indicating it would commence a bifurcated process to address Lookback issues that arose as part of the Ninth Circuit's remand in *Pacific Northwest Generating Cooperative, et al. v. Bonneville Power Administration*, 550 F.3d 846 (9th Cir. 2008) (*PNGC*). The suit challenges the validity of BPA's FY 2007 – 2011 direct-service industrial customer (DSI) service construct and contracts. The June 10 announcement indicated that, in early July, BPA planned to issue a draft record of decision, pursuant to the Court's instructions, on "the applicability and construction of the severability clause, the damage waiver, and the physical power sale option."

BPA's original announcement reflects BPA's view, as well as the view of a number of interested parties, that BPA should act as promptly as reasonably possible in resolving issues related to the Lookback. However, BPA also acknowledged that the timing of events under this process might have to be adjusted to accommodate any decisions of the court relevant to the Lookback determination.

In this light, BPA has reconsidered its earlier announcement. The court is still reviewing its original decision pursuant to the filing of petitions for rehearing filed by the Port Townsend Paper Company and BPA. Also, oral arguments were recently completed on an expedited basis in the court's review of challenges to the contract amendment providing service to Alcoa through FY09. Thus, the case is still within the Court's original and continuing jurisdiction, no mandate has been issued, and the court is free to change its opinion until it issues a mandate. It would be unfortunate indeed if BPA were to issue a draft ROD on the DSI Lookback only to have the Court issue an opinion, or opinions, shortly thereafter that have a material effect on BPA's consideration of the salient issues.

Due to this uncertainty, BPA has determined that it would be prudent to delay issuing the draft record of decision until no earlier than 30 days after the mandate issues in *PNGC* or December 1, 2009. In the meantime, BPA will continue to evaluate pertinent issues and await the Court's final determination in the hope that the Court will provide some degree of finality in the near future.

If you have additional questions about this issue, please call Mark Symonds at (503) 230-3027 or Heidi Helwig of the Public Affairs Office at (503) 230-3458.

Sincerely,

//s// Allen Burns

Allen Burns
Acting Deputy Administrator

bcc:

S. Wright – A-7
A. Burns – D-7
C. Brannon – DK-7
CCIS Authentication – KSC-4
R. Roach – L-7
J. Wright – LP-7
S. Cannady – PT-5
H. Clark – PTL-5
L. Kitchen – PTL-5
Official File – PTL-5

HClark:sgc:3662:7/23/2009 (W-PTL-5-W:\P\PT\PTL\DSI_recent_KEEP\Letter to region - delay in DSI Lookback - 072009.doc)

Attachment C

20.5 aMW Power Sale To Port Townsend Paper Company For The Period November 15, 2009 Through December 31, 2010 – Administrator's Record of Decision

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

20.5 aMW POWER SALE TO PORT TOWNSEND PAPER COMPANY FOR THE PERIOD NOVEMBER 15, 2009 THROUGH DECEMBER 31, 2010

ADMINISTRATOR'S RECORD OF DECISION

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November 13, 2009

BACKGROUND

In September 2006, the Bonneville Power Administration ("BPA") entered into a surplus firm power sales agreement (the "BPA/Clallam Contract") with Public Utility District No. 1 of Clallam County, Washington ("Clallam"), whereby BPA agreed to sell to Clallam 17 aMW for the period October 1, 2006, through September 30, 2011. The power to be sold by BPA to Clallam under the BPA/Clallam Contract was for the purpose of, and was expressly conditioned upon, resale by Clallam to Port Townsend Paper Company ("Port Townsend") under a contract by and between Clallam and Port Townsend (the "Clallam/Port Townsend Contract"). The rate paid by Port Townsend under the Clallam/Port Townsend Contract equaled the rate paid by Clallam under the BPA/Clallam Contract, plus a mark-up to cover certain of Clallam's costs associated with providing such service. Petitions for review of the BPA/Clallam Contract were subsequently filed in the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit" or "Court").

In December 2008, the Ninth Circuit issued its opinion in *Pacific Northwest Generating Cooperative v. Bonneville Power Administration*, 550 F.3d 846 (2008) ("*PNGC I*"), in which the Court, among other things, held that the rate in the BPA/Clallam Contract was below both the market rate and the Industrial Firm (IP) Power rate and was therefore invalid. *Id*. at 879.

Port Townsend filed a petition for panel rehearing in February 2009, and BPA filed a motion seeking clarification of certain aspects of the opinion in March 2009. In the meantime, so as not to be delayed when the mandate did issue, BPA posted for public comment on June 22, 2009, a draft contract by and between BPA and Port Townsend for the period October 1, 2009, through September 30, 2011, (the "Two-Year Contract") which would have served as a replacement contract for the two years remaining in the BPA/Clallam/Port Townsend transaction. Comments on this draft contract were due July 10, 2009.

On August 5, 2009, the Court amended its original opinion in certain respects in response to BPA's petition but denied Port Townsend's requests for panel rehearing. Port Townsend then filed a motion to stay issuance of the mandate in the case for 90 days. On

August 14, 2009, the Court issued an order staying issuance of the mandate in *PNGC I* for 30 days "to provide Port Townsend and the Bonneville Power Administration time to attempt to arrange for the provision of power to Port Townsend." BPA had prepared an interim contract it believed complied with *PNGC I*, and the parties entered into that contract for the period September 1, 2009, through September 30, 2009 (the "September Interim Contract"). That contract is described in *Bonneville Power Administration Record of Decision For 30-Day Sale of 17 MW to Port Townsend Paper Company Commencing September 1, 2009*, issued on August 27, 2009.

After close of the comment period on the Two-Year Contract, BPA determined that it was unlikely to make a final determination regarding that contract before October 1, 2009. BPA decided more time was needed to fully consider the issues surrounding DSI service in general; BPA believed that any multi-year contract with a DSI customer should be informed by the Court's disposition of petitions for review challenging an amendment to BPA's power sales contract with Alcoa entered into in response to *PNGC I*. That amendment provided financial benefits to Alcoa for a nine month period commencing on January 1, 2009, and ending on September 30, 2009. BPA believed the Court's disposition of those petitions could provide additional clarity with respect to the legal requirements for providing service to the DSIs, including Port Townsend.

On August 28, 2009, the Ninth Circuit issued its opinion in the case challenging the Alcoa amendment in *Pacific Northwest Generating Cooperative v. BPA*, Slip Op. 09-70228 (August 28, 2009) ("*PNGC II*"). *PNGC II* raised additional issues to be resolved regarding service to DSI customers, and BPA concluded it could not reach a final decision whether to offer the Two-Year Contract referenced above prior to October 1, 2009. Specifically, BPA determined it needed additional time to evaluate *PNGC II*, and make a determination, in light of that opinion, whether offering a multi-year contract to the DSIs, including Port Townsend, is consistent with "sound business principles" as BPA believes that standard was described in *PNGC II*.

However, in order to avoid disruption of power service at the Port Townsend facility, and because it could do so consistent with the most conservative reading of *PNGC II*, BPA offered a second interim contract, this one for the period October 1, 2009, through October 31, 2009 (the "October Interim Contract"). BPA forecast that it would earn positive net revenues under the October Interim Contract, and concluded based on that finding that the contract complied with even the most conservative reading of the Court's direction regarding "sound business principles" in *PNGC II*. That contract is described in *Bonneville Power Administration 31-Day Sale of 20 MW to Port Townsend Paper Company Commencing October 1, 2009 – Administrator's Record of Decision*, issued on September 30, 2009.

Prior to expiration of the October Interim Contract, BPA offered a third interim contract, this one for the period November 1, 2009, through November 7, 2009, and then a fourth interim contract for the period November 8, 2009 through November 14, 2009 (together the "November Interim Contracts"), in order to provide BPA with additional time to complete its evaluation of the comments filed by parties with respect to modifications made to the Two-Year Contract (referred to hereafter as the "Block Contract" as described immediately below), and to draft this record of decision detailing its final decisions with respect to that contract.

BLOCK POWER SALES AGREEMENT

On October 8, 2009, BPA posted for public comment a draft power sales contract with Port Townsend for the period November 1, 2009, through December 31, 2010, (the "Block Contract") whereby BPA proposed to sell to Port Townsend up to 20.5 aMW of power over the term priced pursuant to the IP-10 rate schedule.[1] Comments were due October 19, 2009. This record of decision addresses the comments received, and provides the rationale supporting BPA's decision to enter into the Block Contract, which modifies the Two-Year Contract to comport with *PNGC II*.

1. Description of the Block Contract

Subject to certain possible downward adjustments discussed below, BPA will sell to Port Townsend, and Port Townsend will purchase from BPA, up to 20.5 aMW (up to 21 MW on any hour) of firm power at the point of receipt, over the 14-month term of the Block Contract. Block Contract, Exhibit A.[2] The rationale for making available up to 20.5 aMW is described separately below in section 2. As noted, the rate paid by Port Townsend will be as specified in the IP-10 rate schedule. Block Contract, section 3.1.

Port Townsend's obligation is take-or-pay, but, as noted by Snohomish PUD in its comments (Snohomish at 2), Port Townsend's take-or-pay obligation equals 13 aMW each month, not 20.5 aMW. Block Contract, section 4.1. The take-or-pay amount is less than the 20.5 aMW maximum contract demand due to occasional disruptions experienced in the production process in paper and pulp operations. Snohomish PUD noted in its comments that the contract language "suggests Port Townsend is only required to compensate BPA should [Port Townsend] purchase dip below 13 aMW" and "any fluctuation between 13 aMW and 20.5 aMW is therefore permissible." Snohomish at 2. Snohomish goes on to state its concern that "this conflicts with the general notion of an advance purchase of a specific block of energy." Snohomish at 2. In other words, Snohomish is suggesting that if BPA is offering a block of up to 20.5 aMW to Port Townsend, that BPA will likely purchase resources to serve that firm obligation, and that Port Townsend's take-or-pay obligation should equal the full 20.5 aMW. However, as discussed at length in section 4 below, BPA expects to serve this load from inventory and does not anticipate the need to make specific additional purchases to serve the Port Townsend load. In particular, BPA does not anticipate the need to make *advance* purchases to serve the Port Townsend load. Additionally as further discussed,

[1] BPA, Clallam, and Port Townsend have agreed this transaction replaces deliveries of surplus firm power to Port Townsend under the BPA/Clallam and Clallam/Port Townsend Contracts through September 2011, and those contracts will be terminated upon commencement of deliveries under the Block Contract.

[2] Section 4.3 of the Block Contract provides for Port Townsend to take up to 21 MWs from BPA on any hour, since power may only be scheduled in whole megawatts.

curtailments allowed under the Block Contract are not forecast to have an advantageous or disadvantageous effect on the equivalent benefit analysis. Therefore, BPA does not anticipate being harmed by, nor does it anticipate any effect on its equivalent benefits analysis given, the 13 aMW take-or-pay amount.

While this take-or-pay obligation is waived to the extent Port Townsend curtails its load pursuant to section 5, Port Townsend remains obligated to pay BPA any amount by which the market value of such curtailed power is below the applicable IP rate. In response to a comment by the Springfield Utility Board (SUB at 7-8) concerning the time lag between when such damages may be incurred by BPA and the time they are paid by Port Townsend, BPA has changed the contract to provide that Port Townsend pay BPA any amounts owing under section 6 of the Block Contract as part of the power bill issued for the month such amounts are incurred, rather than at the end of the fiscal year.[3] In any case, Port Townsend historically has operated its facility with limited curtailments, and while it is unlikely that it will curtail its load over the term of the Block Contract, if it does it is unlikely such curtailment would be for a long duration.

Port Townsend is obligated to prepay each month for 13 aMW. To the extent that Port Townsend takes more power than 13 aMW during the month, then it will pay for such incremental amounts in the following month. Block Contract, Exhibit C. However, to mitigate the payment risk exposure associated with power deliveries in a month in excess of 13 aMW, prior to commencement of deliveries under the contract Port Townsend will pay BPA approximately $213,000 as security. This amount represents the difference between 13 aMW (which Port Townsend is prepaying each month) and 20.5 aMW (the most power Port Townsend can take in any month), multiplied by the highest IP rate over the term of the contract. Block Contract, Exhibit C, section 6. In addition, BPA has the right to demand additional assurance from Port Townsend in the event reasonable grounds for insecurity arise with respect to Port Townsend's performance. Block Contract, section 16.8. If Port Townsend fails to make any payment within 3 business days of its due date, BPA may suspend its own performance, and if Port Townsend fails to make any payment within 7 days of the due date, BPA may terminate the contract. BPA believes the foregoing provisions taken together provide it with ample protection against any default by Port Townsend.

Port Townsend will provide power reserves to BPA under the Block Contract, as specified in BPA's 2010 General Rate Schedule Provisions and Exhibit H of the contract.

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[3] The curtailment provisions are taken from earlier, multi-year DSI contracts. The original purpose behind payment by the DSI of any curtailment damage amounts at the end of the fiscal year, as opposed to monthly, was to allow BPA to calculate a net amount over the entire year, because in the event BPA obtained revenues from remarketed curtailed power in excess of IP revenues, such amounts were to be used as a credit to be applied against damages resulting when BPA revenues from remarketed curtailed power were less than IP revenues, with this calculation being performed at the end of the contract term or fiscal year. As now drafted, in the event Port Townsend pays BPA damages under section 6 in one or more months, but over the term BPA calculates Port Townsend would not owe any amounts because on a net basis BPA remarketed any curtailed power above the IP rate, then any such monthly payments made to BPA by Port Townsend will be refunded. This eliminates the credit risk identified by SUB in its comments.

Block Contract, section 5.2. Issues raised in comments with respect to the reserves to be provided by Port Townsend are addressed in section 6 below.

2. Summary of Comments

BPA received written comments from 12 parties, including from individual public utility customers Springfield Utility Board (SUB), Clatskanie PUD, Canby Utility Board, and Snohomish PUD; umbrella groups representing public utility customers (Public Power Council (PPC)[4], Pacific Northwest Generating Cooperative (PNGC), and Northwest Requirements Utilities (NRU)), and each of the DSIs (Alcoa, Columbia Falls Aluminum Company (CFAC), and Port Townsend).

Public customer comments focused on whether the market price forecast BPA is using to measure the cost (or benefit) of the Block Contract is too low, thereby underestimating potential costs, in the event BPA would need to make market purchases to support the sales to Port Townsend, or the lost opportunity cost associated with selling to Port Townsend in lieu of selling that power into what they believe will be a higher priced market (relative to the IP rate). PPC at 1-2; Canby at 1-2; NRU at 1; PNGC at 2; SUB at 2-6; Snohomish at 2. Likewise, many of these same comments question whether BPA should be basing its revenue analysis of the Block Contract on a market price forecast at all, and suggest instead that BPA should be using, or at a minimum that its forecast is failing to adequately take into account, current forward market prices, which reflect higher prices than contained in BPA's forecast, and which they apparently believe are a better indicator of actual future prices. PPC at 2; Canby at 1; PNGC at 2; SUB at 4. Some of the public customers expressly reiterated the position they have taken elsewhere that the Ninth Circuit's opinion in *PNGC II* requires that BPA demonstrate that its revenues from an IP sale would be expected to be greater than a sale at market, or articulate a similar position. PPC at 1-2 (recent decisions require BPA to demonstrate service to DSI will result in financial benefit to BPA); PNGC at 2 (joining PPC's comments); SUB at 8 (Block Contract benefits only Port Townsend and not region "as a whole"); Canby at 2 (BPA must "make money or break even"); NRU at 1 (Block Contract attempts to meet *PNGC II* by demonstrating positive net revenues compared to a market sale).

Several comments, in particular comments submitted by SUB, question the validity of the natural gas price forecast component of BPA's electricity market price forecast. SUB at 2-4. SUB believes that increases in gas market spot prices and gas futures prices at the time comments were submitted are evidence that BPA's current gas price forecast is too low, and that even using BPA's gas price forecast from the WP-10 rate case, "the net present value" of the Block Contract to BPA is a negative $1.8 million.

Public customers also questioned whether BPA will be able to serve Port Townsend from inventory, or if it will be required to make market purchases to serve some or all of the

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[4] The Industrial Customers of Northwest Utilities (ICNU), an umbrella group representing the industrial customers of BPA's public preference utility customers, filed comments jointly with PPC.

load. PPC at 2; Canby at 1; PNGC at 2. PPC, SUB, and PNGC also questioned whether Port Townsend would be able to provide the reserves contemplated by the Block Contract in the event BPA calls on them, and PNGC posited the reserves may be of little value given the relatively small size of the Port Townsend load, while SUB noted that such reserves will be unavailable (and therefore worthless) in the event Port Townsend curtails its load. PPC at 2; SUB at 7; PNGC at 2. For its part, Snohomish commented that the exhibit addressing the details of reserves in the Block Contract is unclear in several respects, including the return energy provisions, and that the contract appears to provide that Port Townsend would receive compensation for providing reserves in addition to the reserves credit embedded in the IP rate. Snohomish at 2-3.

SUB and Canby each commented that BPA has inadequately addressed certain risks inherent in a 14-month sale to Port Townsend, in particular the risk that market prices will trend significantly higher than BPA's forecast, including in the event a threatened drier than average water year materializes, leading to costs that have not been accounted for by BPA. SUB at 4-5; Canby at 2. Similarly, PNGC suggested that the contract be amended to cap BPA's exposure to market purchases equal to the IP rate, and to allow BPA to remarket power under the Block Contract in the event market prices exceed the IP rate by some "reasonable margin," which PNGC noted could be as little as ten percent above the IP rate. PNGC at 2.

Port Townsend expressed concern that the relatively short-term of the Block Contract "impairs the long-term planning so important to an industrial customer such as Port Townsend." Port Townsend at 1. Citing BPA's letter that accompanied publication of the draft Block Contract for public comment, Port Townsend commented that it appeared BPA was taking the position that *PNGC II* prohibits a power sale to a DSI "unless the price is above the market price of power for the time period the power is offered," and that it believed such a reading is at odds with the plain language of that opinion. *Id.* at 2. Alcoa made a similar comment, citing extensively from *PNGC II* to support its position that BPA "need not conduct an accounting analysis that demonstrates that the economic benefits of the contract are equal to, or exceed the cost of providing service" to a DSI. Alcoa at 1-2. CFAC echoed this position, and also commented that BPA needed to take into account transmission costs it would avoid by making the sale to Port Townsend in lieu of selling the power into the market. CFAC at 1.

Port Townsend offered several points it believed BPA needed to consider in making its decision regarding the Block Contract, including the fact Port Townsend's load is "a predictable and stable 24/7 load"; that the Block Contract addresses BPA's credit risk; that Port Townsend has been a BPA direct-service customer for over 60 years, and but for its legal status as a DSI, that it would be entitled to be served by its local utility with BPA power for 40 percent less cost; and that BPA will be locking-in a higher rate "on in-region power sales for all service to Port Townsend, and not just for the power sold during higher-cost periods that Port Townsend otherwise has the right to call upon." Port Townsend at 2.

Parties' comments are addressed herein.

3. Contract Demand of 20.5 aMW

As noted above, BPA will make available to Port Townsend up to 20.5 aMW over the term of the Block Contract, and up to 21 MW on any hour.[5] SUB commented that BPA "has not clearly articulated" why it is proposing "to give Port Townsend more power benefits." SUB at 6.

20.5 MW equals Port Townsend's historic contract demand, as provided by the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. §§ 839, 839c(d)(1)(B) ("Northwest Power Act"), as implemented and established in Port Townsend's 1981 power sales contract. Section 5(d)(1)(B) of the Northwest Power Act directed BPA to offer each DSI an initial long-term contract in an amount, referred to generally as its "contract demand," equivalent to the amount of power each DSI was entitled to under its then existing BPA power sales contract. For Port Townsend, this amount was 16.6 MW. The resulting 1981 DSI power sales contracts provided that a company's contract demand could be increased for certain efficiency improvements and modifications to plant equipment, including the addition of certain environmental protection equipment. These increases were referred to in the 1981 DSI contracts as "technological allowances," and in March 1996 Port Townsend applied to BPA for such an increase associated with its so-called old corrugated cardboard ("OCC") facility load (see Attachment A). BPA approved the request in January 1997, thereby increasing Port Townsend's contract demand (*i.e.*, the maximum amount of IP power BPA may legally provide to Port Townsend) from 16.6 MW to 20.5 MW (see Attachment B).

In the record of decision for the October Interim Contract, BPA inadvertently stated that it had concluded in a 2005 record of decision that its 1997 determination that the OCC expansion load qualified as a technological allowance was incorrect, but qualified instead as a plant expansion under its so-called Atochem policy, and was therefore eligible for PF service from Clallam. In fact, BPA did not conclude in the 2005 record of decision that its 1997 determination was incorrect, and the two things – a technological allowance under the 1981 contract and a plant expansion per the Atochem policy – while not equivalent, are not mutually exclusive. In other words, BPA's 1997 determination regarding the technological allowance remains a valid agency final decision, and Port Townsend's historic contract demand is currently 20.5 MW.

However, BPA's conclusion in the 2005 record of decision that the approximately 3 aMW of production load at the OCC facility could be served by Clallam at the PF rate also remains a valid final decision. As noted above, to the extent this 3 aMW of load is shifted to Clallam, then Port Townsend's contract demand under the Block Contract will be reduced by the same amount.[6] Nevertheless, inasmuch as BPA is forecasting, as

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[5] The Block Contract permits Port Townsend to avail itself of 21 MW in any hour because power may be scheduled only in whole megawatts. For purposes of this discussion BPA's uses the 20.5 MW number.

[6] As noted in the record of decision for the October Interim Contract, Clallam and Port Townsend have undertaken negotiations regarding the terms and conditions under which Clallam would serve OCC load.

discussed in section 5 below, that the average IP rate for the term of the Block Contract exceeds the average market price over the same period, BPA will benefit from increased revenues to the extent Port Townsend avails itself of the opportunity to take as much of its full contract demand of 20.5 MW, rounded up to 21 MW on any hour, or its full average contract demand over the term of the Block Contract of 20.5 aMW, as its operations warrant. For its part, Port Townsend will benefit from the firm availability of up to 20.5 MW, rounded up to 21 on any hour, of IP priced power to meet most of its load requirements, with only amounts above 20.5 aMW priced above IP.[7]

4. BPA Does Not Anticipate Making Additional Market Power Purchases to Serve Port Townsend

Several parties in comments questioned whether BPA believes it will be able to serve Port Townsend over the term of the Block Contract without acquiring additional power. See PPC at 2; Canby at 1; PNGC at 2. PNGC argues that if market prices turn out to be higher than BPA's is forecasting, which PNGC believes will be the case, then BPA is underestimating the cost to serve Port Townsend under the Block Contract. *Id*. BPA does not forecast the need to make purchases specifically to serve Port Townsend under the Block Contract, although, as explained below, BPA has forecast the need to make some purchases, including some normal "balancing" purchases, to meet its total load obligations over the FY 2010 through FY 2011 rate period, under critical (*i.e.*, very poor) water conditions.[8]

Pursuant to BPA's most recent load and resources study contained in the 2009 Pacific Northwest Loads and Resources Study ("2009 White Book"), which forecasts loads and resources for both the Federal system and the region as a whole for the 10-year period OY 2010-2019,[9] BPA is forecast to have a surplus of approximately 1,731 aMW on an average annual basis under the middle 80 percent of the historical water conditions for the term of the Block Contract. See 2009 White Book, Table 8 at 40, and Exhibits 11-12 at 104-107. Port Townsend's load under the Block Contract represents less than 2 percent of that forecast surplus. In the recently completed WP-10 Wholesale Power and

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[7] Section 4.3 of the Block Contract provides for Port Townsend to take up to 21 MWs from BPA on any hour, since power may only be scheduled in whole megawatts. To the extent that Port Townsend scheduled more than 20.5 aMW during any month off the BPA system, it would pay BPA for such power pursuant to the Unauthorized Increase Charge contained in BPA's 2010 General Rate Schedule Provisions. The Unauthorized Increase Charge is a penalty rate that reflects market conditions and is three to ten times the IP-10 rate.

[8] 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.

[9] Operating Year (OY) in the White Book is the 12-month period August 1 through July 31. For example, OY 2010 is August 1, 2009, through July 31, 2010.

Transmission Rate Adjustment Proceeding (WP-10) BPA forecast surplus available for secondary sales of 1,694 aMW for FY 2010 (which encompasses most of the term of the Block Contract) and 1,751 aMW for FY 2011 (see Table 4.8.1: Secondary Sales, WP-10-FS-BPA-05A, at 88).

BPA's surplus forecast takes into account certain market purchases, shown here, that BPA forecasts it may make in order to meet its load obligations under critical (or very poor) water conditions in FY 2010 and FY 2011 (see Tables 4.8.2, 4.8.3, 4.8.4, WP-10-FS-BPA-05A, at 89-91):

	FY2010	FY2011
Balancing Purchases	193 aMW	149 aMW
Winter Hedging Purchases	~80 aMW	~80 aMW
Augmentation Power Purchases	476 aMW	680 aMW

Even after adjusting out these purchases, BPA expects to be surplus under average water conditions, and as such does not anticipate the need to alter its purchasing strategy for the sales made to Port Townsend. In any case, the WP-10 Loads & Resources Study includes 403 aMW for service to the DSIs, including 17 aMW of service to Port Townsend (see Table 4.6.2, WP-10-FS-BPA-05A, at 77), and so BPA has already factored such sales into the above referenced table of possible FY 2010 and FY 2011 purchases. In addition, total DSI load over the term of the Block Contract may well be substantially less than this 403 aMW amount, making market purchases in addition to those referenced above even less likely.

Thus, BPA does not anticipate the need to make specific additional purchases to serve the Port Townsend load. Nevertheless, if any additional purchases become necessary, the average market price during the term of the Block Contract, as explained below, is expected to be below the IP rate paid to BPA by Port Townsend. In addition, and as described in more detail below in response to comments that BPA has not adequately accounted for the risks surrounding the Block Contract, BPA has already included approximately $37 million in DSI service costs in its base rates for each year in the period covered by the Block Contract. Therefore, even if it turns out that BPA does incur some unexpected power purchase costs to serve Port Townsend, it is highly unlikely such costs would exceed the costs BPA already included in its WP-10 rates for DSI service, or even that portion of the $37 million that could be attributed to Port Townsend.[10]

[10] The 20.5 aMW service to Port Townsend contemplated in the Block Contract represents approximately five percent of the 403 aMW of DSI service contemplated in WP-10. BPA has already included approximately $37 million in DSI service costs in its base rates for each year in the period covered by the Block Contract. Therefore, the five percent share of the $37 million that is attributable to Port Townsend is approximately $1.8 million. Given an average annual IP rate of $34.60 per MWh, market prices would have to exceed $44.90 per MWh for the cost to BPA of the service to Port Townsend to exceed the $1.8 million per year that BPA has included in its base rates for the fiscal years 2010 and 2011. Such an average price for a flat load over all of FY2010 is expected to occur in less than 10% of the 3,500 games considered in the uncertainty analysis that is part of BPA's most recent market price forecast. (See generally WP-10-FS-BPA-05, WP-10-FS-BPA-05A and WP-10-FS-BPA-04)

5. BPA Forecasts It Will Accrue Positive Net Revenues Under the Block Contract

For the reasons outlined in this section 5, BPA forecasts that the revenues it will accrue from the sale of up to 20 aMW to Port Townsend at the IP rate will exceed by approximately $75,000 forecast revenues BPA could otherwise obtain from selling that power into the market. See Tables 1-5 below. As a consequence, BPA believes service to Port Townsend under the Block Contract is consistent with even the most conservative interpretation of "sound business principles" as described in *PNGC II*, to wit, that service to a DSI only can be provided if benefits equal or exceed costs.

In addition, BPA believes its forecast of positive net revenues is probably conservative, inasmuch as a firm sale to Port Townsend could redound in certain additional tangible and intangible benefits to BPA's operations. Tangible and quantifiable benefits include, for example: a) avoided transmission costs for a portion of surplus sales;[11] and b) a projected increase in the market price of electricity for BPA's other surplus sales as a result of DSI load operating.[12] Other intangible and qualitative benefits include, for example: a) the potential for BPA's sales to the DSIs at the IP rate to mitigate the risk that BPA's surplus sales may be impacted by periods of so-called "negative pricing" that are the result of rationale economic behavior by suppliers of generation but not

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[11] When BPA makes a requirements sale, its customers – including Port Townsend – cover the cost of transmission through their own transmission contract. Market prices assume power is delivered by the seller to Mid-C. BPA Power Services must pay those transmission costs to move the power to the Mid-C delivery point in order to realize the full market value for its surplus sales. BPA PS maintains an inventory of transmission to move the surplus power it intends to sell. However, this inventory is not sufficient to move all of the surplus power BPA would sell under all water conditions. As a result, there is a subset of water conditions under which BPA would incur an incremental transmission cost to sell the incremental surplus energy if it did not sign contracts to serve the DSI loads – including the Block Contract with Port Townsend. These incremental transmission costs are avoided when BPA makes an IP sale(s) to the DSIs.

BPA would determine the value of these avoided transmission costs using the same methodology it used in the WP-10 rate proceeding to establish the costs and risks associated with its transmission inventory. Specifically, we would identify the subset of water conditions. Then we would apply the tariff costs established by BPA TS to the incremental transmission need under each water condition. The mean value of the 3,500 games for which this was done represents the forecasted cost of the incremental transmission avoided when BPA makes an IP sale(s) to the DSIs – including the Block Contract with Port Townsend.

The avoided transmission costs are dependent on the combined amount of all DSI sales. For example, BPA's bulk marketing function may have sufficient pre-purchased transmission inventory to cover only an incremental 20.5 aMW sale in a given scenario, but not have sufficient transmission inventory to cover a 20.5 aMW sale to Port Townsend plus a 285 aMW sale to Alcoa.

[12] When BPA serves the DSI loads – including Port Townsend – and they operate – as opposed to not operating if BPA does not sell to them – BPA's surplus sales realize increased revenues because the mean value of prices for electricity for 3,500 games in Western power markets are higher than they would otherwise be had the DSI loads not consumed electricity from Western power markets.

sufficiently addressed by models currently available to forecast prices of electric power;[13] and b) Port Townsend's provision of additional reserve products or restriction rights to BPA.[14]

However, adjustments for these other benefits to BPA are not included or relied upon here because this 20.5 aMW sale, in and of itself, is not of sufficient magnitude to significantly impact the financial benefit to BPA. However, the accrual of other potential benefits associated with the Block Contract could be significant if the accumulation of additional sales to the DSIs in total were taken into account, resulting in a favorable impact to BPA's forecast of positive net revenues resulting from the Block Contract.

BPA's Projected Revenues Under the Block Contract

BPA's projected monthly revenues under the Block Contract are determined by multiplying the heavy load hour (HLH) and light load hour (LLH) energy entitlements and demand entitlement by their respective IP rates for each month. BPA has calculated revenues under the Block Contract based on the sale of 20 MW of firm power (not 20.5 MW because power is scheduled in whole megawatts) each hour to Port Townsend under the IP-10 rate schedule beginning November 15, 2009, the commencement of Firm Power deliveries pursuant to the Block Contract, as opposed to November 1, 2009 used in BPA's analysis posted on October 13, 2009. In addition, the energy entitlements are the projected amounts of megawatt-hours to be sold by diurnal period each month. The demand entitlement is the megawatt amount consumed during the hour of BPA's system peak.

BPA's analysis also assumes that Port Townsend operates subsequent to its execution of the Block Contract, at which time BPA believes its decision to operate will be made based primarily on the prices for its production output which are independent of power prices. Therefore, curtailments allowed under the Block Contract are not forecast to have an advantageous or disadvantageous effect on this analysis. Nonetheless, the analysis is proportional, so whether Port Townsend's usage under the Block Contract is 13 aMW, 20.5 aMW, or some amount in between, the term of BPA's net positive revenue conclusion would remain the same.

BPA's projected monthly revenues are then accumulated and the result is illustrated in Tables 1 and 2:

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[13] Negative pricing, a phenomenon associated with certain renewable energy resources that receive tax or other monetary incentives associated with their output, occurs when, in certain market situations, the value of those incentives exceed the cost to a resource owner of paying counterparties to take its power. See, *e.g*. *Frequent negative power prices in the West region of ERCOT result from wasteful renewable power subsidies*, Knowledge Problem, November 20, 2008. http://knowledgeproblem.com/2008/11/20/frequent_negati/

[14] See Block Contract, section 5.3, Additional or Alternative Arrangements for Power Reserves.

TABLE 1 - Usage and Rates

Month	Port Townsend Usage			IP-10 Rates		
	Demand (kW)	HLH (MWh)	LLH (MWh)	Demand ($ / kW)	HLH ($ / MWh)	LLH ($ / MWh)
Nov-09	20,000	3,840	3,840	$2.19	$33.33	$29.58
Dec-09	20,000	8,320	6,560	$2.30	$35.24	$31.13
Jan-10	20,000	8,000	6,880	$1.96	$38.46	$32.24
Feb-10	20,000	7,680	5,760	$1.99	$37.72	$31.73
Mar-10	20,000	8,640	6,220	$1.85	$35.94	$30.08
Apr-10	20,000	8,320	6,080	$1.74	$32.23	$26.95
May-10	20,000	8,000	6,880	$1.44	$31.69	$22.29
Jun-10	20,000	8,320	6,080	$1.32	$31.18	$23.29
Jul-10	20,000	8,320	6,560	$1.61	$33.33	$28.66
Aug-10	20,000	8,320	6,560	$1.89	$37.31	$31.40
Sep-10	20,000	8,000	6,400	$1.96	$36.49	$32.26
Oct-10	20,000	8,320	6,560	$2.05	$31.92	$27.01
Nov-10	20,000	8,000	6,420	$2.19	$33.33	$29.58
Dec-10	20,000	8,320	6,560	$2.30	$35.24	$31.13
Jan-11	20,000	8,000	6,880	$1.96	$38.46	$32.24

TABLE 2 - BPA's Projected Revenue

Month	Revenues by Rate Determinant			Projected IP Revenue	
	Demand ($)	HLH ($)	LLH ($)	Month ($)	Cumulative ($)
Nov-09	$43,800	$127,987	$113,587	$285,374	$285,374
Dec-09	$46,000	$293,197	$204,213	$543,410	$828,784
Jan-10	$39,200	$307,680	$221,811	$568,691	$1,397,475
Feb-10	$39,800	$289,690	$182,765	$512,254	$1,909,730
Mar-10	$37,000	$310,522	$187,098	$534,619	$2,444,349
Apr-10	$34,800	$268,154	$163,856	$466,810	$2,911,158
May-10	$28,800	$253,520	$153,355	$435,675	$3,346,834
Jun-10	$26,400	$259,418	$141,603	$427,421	$3,774,254
Jul-10	$32,200	$277,306	$188,010	$497,515	$4,271,770
Aug-10	$37,800	$310,419	$205,984	$554,203	$4,825,973
Sep-10	$39,200	$291,920	$206,464	$537,584	$5,363,557
Oct-10	$41,000	$265,574	$177,186	$483,760	$5,847,317
Nov-10	$43,800	$266,640	$189,904	$500,344	$6,347,660
Dec-10	$46,000	$293,197	$204,213	$543,410	$6,891,070
Jan-11	$39,200	$307,680	$221,811	$568,691	$7,459,761

BPA compared these IP revenues to forecasted revenues that would be obtained in the event this power was sold into the market over the term of the Block Contract, using the market price forecast from the WP-10 rate proceeding, but with an updated natural gas forecast component. BPA routinely shapes its inventory to meet its contracted loads and manages its surplus inventory by purchasing and selling in the Pacific Northwest power market as described in BPA's WP-10 rate proceeding.[15] BPA established its forecast of Mid-Columbia trading hub electricity prices in the WP-10 rate proceeding to value these purchases and sales.[16]

As noted, for the period covered by the Block Contract BPA has updated its natural gas forecast from that used in BPA's WP-10 rate proceeding to reflect a more contemporary understanding of natural gas fundamentals, and to be consistent with the natural gas forecast used in BPA's draft Resource Program released September 30, 2009. BPA's updated natural gas forecast is discussed in more detail below. In the absence of the Block Contract, BPA would have one less firm power sale obligation included in its aggregated portfolio load shape to (potentially) purchase for and would expect to have more surplus energy to sell in the market. As illustrated in Table 3, BPA has forecast the revenues it would otherwise obtain from the market, using the same electricity market price forecasting methodology applied in the WP-10 rate proceeding, and incorporating BPA's recently updated forecast of natural gas prices.

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

	Forecasted Market		**Forecasted Revenues Obtained from the Market**			
Month	HLH Price ($ / MWh)	LLH Price ($ / MWh)	HLH ($)	LLH ($)	Month ($) (HLH + LLH)	Cumulative ($)
Nov-09	$28.75	$26.38	$110,386	$101,285	$211,671	$211,671
Dec-09	$30.61	$27.41	$254,686	$179,826	$434,512	$646,183
Jan-10	$34.13	$29.51	$273,032	$203,019	$476,051	$1,122,233
Feb-10	$34.46	$29.77	$264,654	$171,473	$436,127	$1,558,361
Mar-10	$33.92	$29.16	$293,105	$181,373	$474,478	$2,032,839
Apr-10	$32.95	$28.05	$274,139	$170,563	$444,702	$2,477,541
May-10	$33.93	$24.45	$271,455	$168,220	$439,675	$2,917,217
Jun-10	$34.33	$26.33	$285,619	$160,085	$445,704	$3,362,921
Jul-10	$37.33	$32.18	$310,572	$211,074	$521,646	$3,884,566
Aug-10	$42.48	$35.63	$353,413	$233,703	$587,116	$4,471,682
Sep-10	$42.86	$38.00	$342,871	$243,178	$586,049	$5,057,731
Oct-10	$43.31	$36.85	$360,342	$241,727	$602,070	$5,659,801
Nov-10	$45.36	$40.59	$362,894	$260,574	$623,467	$6,283,268
Dec-10	$48.81	$43.42	$406,097	$284,854	$690,951	$6,974,219
Jan-11	$50.70	$42.13	$405,610	$289,834	$695,445	$7,669,664

BPA determined its net benefit of serving Port Townsend at the IP rate for each month by subtracting the opportunity cost forecast to be obtained in the market detailed in Table 3 from the projected IP revenues described in Table 2. BPA's net benefit (before adjustments to reflect the value of reserves) is provided in Table 4:

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15 Refer 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, BPA's need for shaping purchases and its ability to make surplus sales. See WP-10-FS-BPA-04, at 21.

16 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-Columbia electricity prices in the WP-10 rate proceeding. See generally WP-10-FS-BPA-03.

TABLE 4 - BPA's Net Benefit before Adjustment

Month	Net Revenue or (Cost) Month ($)	Net Revenue or (Cost) Cumulative ($)
Nov-09	$73,704	$73,704
Dec-09	$108,898	$182,601
Jan-10	$92,640	$275,242
Feb-10	$76,127	$351,369
Mar-10	$60,141	$411,510
Apr-10	$22,107	$433,617
May-10	($4,000)	$429,617
Jun-10	($18,283)	$411,334
Jul-10	($24,130)	$387,203
Aug-10	($32,913)	$354,290
Sep-10	($48,465)	$305,826
Oct-10	($118,310)	$187,516
Nov-10	($123,124)	$64,392
Dec-10	($147,541)	($83,149)
Jan-11	($126,753)	($209,903)

Finally, BPA took into account the value to BPA of the reserves Port Townsend is required to make available to BPA under the Block Contract.[17] Sales at the IP rate reflect the value of a right for BPA to obtain operating reserves. 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 firm surplus sale to a sale at the IP rate with reserves. BPA 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. As illustrated by Table 5, this is done for every megawatt-hour of the power not sold to Port Townsend:

[17] Issues raised in comments with respect to reserves are discussed in more detail below

TABLE 5 - BPA's Net Benefit after Adjustments

Month	Value of Reserves		BPA's Adjusted Net Revenue	
	Month ($)	Cumulative ($)	Month ($)	Cumulative ($)
Nov-09	$6,144	$6,144	$79,848	$79,848
Dec-09	$11,904	$18,048	$120,802	$200,649
Jan-10	$11,904	$29,952	$104,544	$305,194
Feb-10	$10,752	$40,704	$86,879	$392,073
Mar-10	$11,888	$52,592	$72,029	$464,102
Apr-10	$11,520	$64,112	$33,627	$497,729
May-10	$11,904	$76,016	$7,904	$505,633
Jun-10	$11,520	$87,536	($6,763)	$498,870
Jul-10	$11,904	$99,440	($12,226)	$486,643
Aug-10	$11,904	$111,344	($21,009)	$465,634
Sep-10	$11,520	$122,864	($36,945)	$428,690
Oct-10	$11,904	$134,768	($106,406)	$322,284
Nov-10	$11,536	$146,304	($111,588)	$210,696
Dec-10	$11,904	$158,208	($135,637)	$75,059
Jan-11	$11,904	$170,112	($114,849)	($39,791)

As a result, this analysis demonstrates how the projected revenues BPA recovers from the 14-month IP sale (through December 2010) to Port Townsend exceed by $75,059 the forecast revenues that BPA would otherwise obtain from the market.

Forward Markets Compared to Market Forecasts

As noted above, a number of parties questioned whether BPA's market price forecast is accurate, including in light of certain forward market prices around the time comments were submitted, which they believe indicate that market power prices during the term of the Block Contract will be significantly higher than BPA is forecasting. See, PPC at 1-2; Canby at 1; NRU at 1; PNGC at 2; SUB at 2-4; Snohomish at 2.

Clearly, the market price forecast is an important component in BPA's forecast of expected net revenues under the Block Contract, serving to measure both the cost associated with purchases, if any, required to serve the Port Townsend load, or the lost opportunity cost, if any, of selling the power earmarked for sale to Port Townsend into the market instead. However, BPA does not agree with the view expressed in a number of comments that current forward market prices are a better indicator of average market prices over the 14-month term of the Block Contract than BPA's market price forecast given BPA does not normally sell or buy forward 14-month strips of power, but rather manages its inventory closer to the actual delivery month. In simplest terms, "forward market prices" are actual prices agreed to between a buyer and seller on any given day for power to be delivered at some time in the future, and therefore represent the price at which two parties are willing to transact *that day* for future delivery; but the market price on that future date of delivery may (and almost certainly will be) either higher or lower. For example, Snohomish commented it received a forward price quote of $59.25 on October 15, 2009, for delivery beginning October 1, 2010, of heavy load hour energy at the Mid-Columbia trading hub. Snohomish, Attachment A. By contrast, a "forecast" of market prices seeks to determine what the actual market price will be on a given day (or hour) over a certain future period. Using the preceding example, a market price forecast would project the likely actual market price for delivery of heavy load hour energy at the Mid-Columbia trading hub on October 1, 2010, based on market fundamentals.

While forward market prices reflect the view – at least of those parties entering into forward market contracts – of a fair market price *that day* for power delivered on a future date, forward markets for electricity are increasingly susceptible to the episodic variability and volatility common in commodity markets. This phenomenon is borne out in current electricity forward market prices which have dropped substantially from the mid-October forward market prices cited by Snohomish in its comments. In the short passage of time, just three weeks from October 15th to November 6th, the flat average of the forward prices observed by BPA for the 14-month term of the Block Contract fell from $46.78 per MWh to $40.30 per MWh and reduced the cost asserted by Snohomish by more than half.[18] This contributes to why BPA believes individual forward market price observations can be a volatile indicator and, as a result, a poor tool to employ for longer-term public policy decisions.

As a general matter, while BPA agrees that the forward market is an important benchmark of near-term market prices, it only comes into play if one is willing to lock in a forward purchase or sale for the period quoted. 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.)

Gas Forecast Component of BPA's Price Forecast

Several parties either challenged the gas forecast component of BPA's price forecast covering the period of the Block Contract, or asked BPA to provide additional detail regarding its gas price forecast. PPC at 2; SUB at 2-5; Snohomish at 1. SUB provided documentation in its comments showing that both spot and futures prices for natural gas had increased around the time its comments were submitted, and concluded that BPA's "analysis used a dated market forecast that does not reflect today's reality." SUB at 4.

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

[18] Please refer to Attachment G for additional detail on forward prices observed by BPA and BPA's re-creation of the analysis submitted by Snohomish in Attachment A to its October 19, 2009 public comment.

the Pacific Northwest, as 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, is 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 fiscal third quarter.

To analyze the period covered by the Block Contract, BPA employed the most recent natural gas price forecast it had developed using the same methodology. This is an update to what BPA used in its WP-10 rate proceeding as an input to its forecast of electricity prices and is identical to the natural gas price forecast used in BPA's draft Resource Program released September 30, 2009. BPA's updated natural gas price forecast was completed at the end of July 2009, during BPA's fiscal fourth quarter. With the exception of the fiscal first quarter, BPA typically updates its natural gas and electricity price forecasts during each quarter to support financial reporting.

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 2009-2010, and increase its forecast in 2011. BPA stated in the draft 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.

See draft *Resource Program*, Appendix B: Market Uncertainties, Bonneville Power Administration, September 30, 2009, 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 2009-2010 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, illustrates that BPA's statement in the draft Resource Program that "the production decline lags the decline in demand" remains apparent, 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) record amount of natural gas in storage continues to demonstrate the anticipated "increase in natural gas storage inventories" contemplated in the draft Resource Program.[19] Furthermore, with the majority of the hurricane season now over with no impacts on supply occurring, the reduction made in the fiscal fourth quarter natural gas price forecast appears to remain 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 below, 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, in alphabetical order, typically included in our comparisons are: Cambridge Energy Research Associates (CERA), the United States Department of Energy's Energy Information Administration (EIA), PIRA Energy Group, and Wood Mackenzie.[20] 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 July through October 2009.

[19] In addition, BPA has detailed, with contemporary information from the Energy Information Administration in Attachment H, ("Natural Gas Statistics"), the continued strength of natural gas production despite steep declines in rigs, the continued slow recovery of natural gas demand, and the record amount of natural gas in storage. See also Short-Term Energy Outlooks from the EIA for September and October showing EIA's lower forecasted Henry Hub Spot Price average for 2010 to $4.78 and $5.02 per Mcf respectively [or $4.64 and $4.87 per MMBtu using EIA's conversion of 1 Mcf = 1.031 MMBtu], *Short-term Energy Outlook*, DOE EIA, September 9, 2009, at 1; *Short-Term Energy and Winter Fuels Outlook*, DOE EIA, October 6, 2009, at 3.

[20] With the exception of the EIA, each of these forecasters considers their information to be proprietary. The vintage of each forecast is late September to early October 2009. EIA forecast is from their *Short-Term Energy and Winter Fuels Outlook* released October 6, 2009.

Figure 1: Henry Hub Natural Gas Spot Price Forecasts

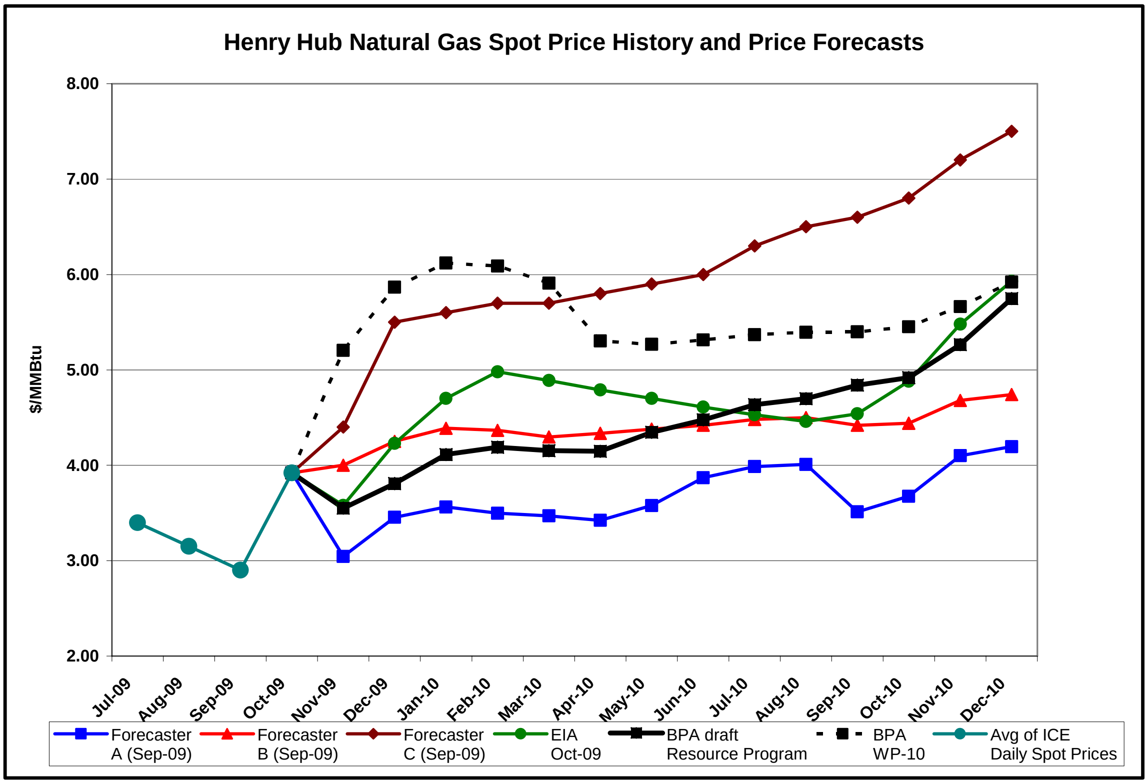


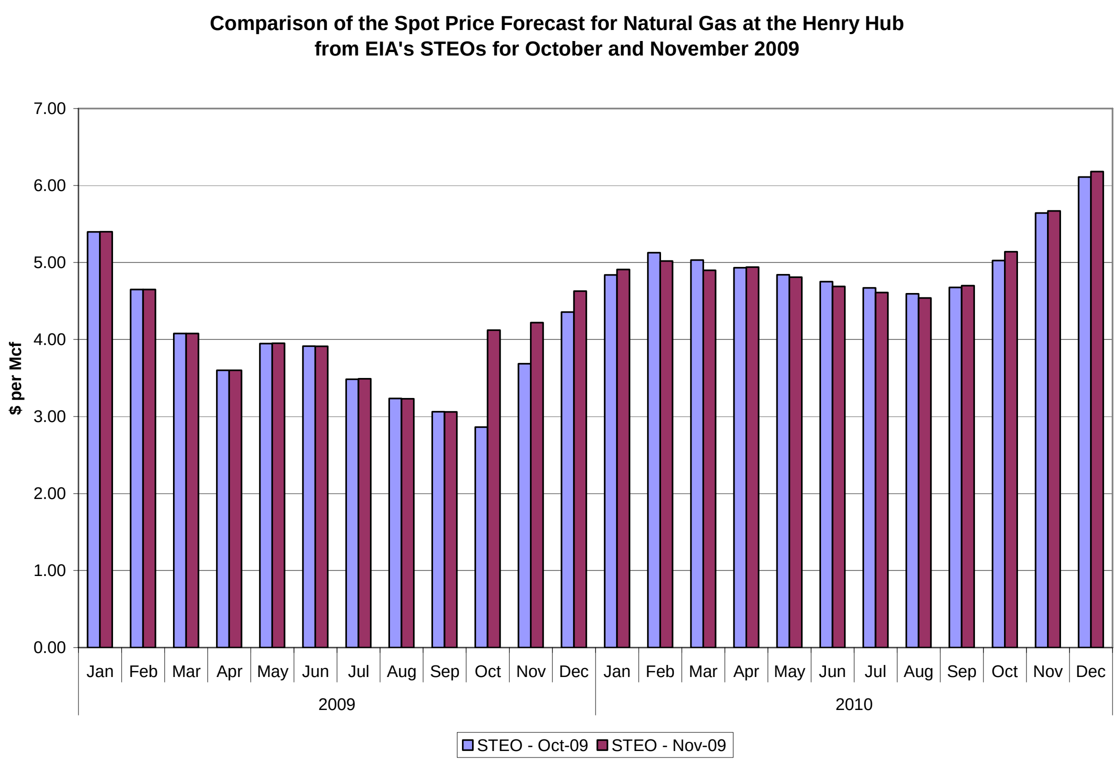
Figure 1 demonstrates that recent spot market prices for natural gas at the Henry Hub have been in the range of $3 to $4 per MMBtu from July to October 2009. This illustration also demonstrates that the forecasts of three other industry experts are $4 per MMBtu or less in November 2009 – the starting month of BPA's equivalent benefits analysis – and their forecasts remain lower than $5 per MMBtu through at least October 2010. BPA's updated forecast of spot price for natural gas at the Henry Hub is consistent with this view reflected by these three industry experts. Only one of the four forecasters expects spot prices for natural gas at the Henry Hub to rise above $5 per MMBtu during the winter of 2009-2010. As a result, BPA believes its updated gas price forecast is reasonable compared to a recent history of Henry Hub spot prices and compared to what other industry experts are expecting.

It is also important to note that BPA may conduct additional evaluation(s) of equivalent benefits in the future. For such future determinations, BPA intends to utilize inputs to the decision process that are as contemporaneous as can reasonably be applied. Such inputs may include updates to BPA's natural gas price forecast, hydroelectric generation forecast, or load forecast. BPA does not believe it would be reasonable to continue using WP-10 rate proceeding inputs when the agency has since updated those inputs.

Finally, SUB asserted in its comments that BPA "used a dated market forecast that does not reflect today's analysis" (SUB at 4) and selectively chose the forecast in BPA's September 2009 resource program as compared to its WP-07 forecast (SUB at 4) in order to support "an unsound and incomplete forecast for Port Townsend Paper…" (SUB at 2).

First, as elaborated above and included in Figure 1, BPA incorporated the Energy Information Administration (EIA) forecast from its October 2009 Short-Term Energy Outlook (STEO), which was released on October 6th, to conclude that its updated gas price forecast is reasonable compared to a recent history of Henry Hub spot prices and compared to what other industry experts are expecting – including EIA in its October 2009 forecast. This was the EIA's most current forecast of natural gas available at the time the analysis was produced and remained so when BPA's analysis was posted 7 days later on October 13th. Furthermore, BPA has reviewed the EIA's November 2009 STEO released on November 10, 2009, and EIA largely sustained the forecast of natural gas prices in their October 2009 STEO employed in Figure 1. As illustrated in Figure 2, EIA's most significant change to their forecast was made to the month of October 2009, increasing it from \$2.86 per Mcf to \$4.12 per Mcf, and their second most significant change was to November 2009, increasing it from \$3.69 per Mcf to \$4.22 per Mcf.

Figure 2 – Comparison of Natural Gas Forecasts from EIA's STEOs



The entirety of October 2009 and 14 days in November 2009 are not within the term of the Block Contract and thus are not germane to BPA's analysis. Furthermore, the historical observations that BPA has incorporated 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 July *through October 2009*. BPA has not incorporated EIA's forecasted value for October 2009 as inferred by SUB.

Regarding the remaining months beginning with December 2009 and extending through December 2010, the EIA went on to say:

> Although [spot] prices [for natural gas at the Henry Hub] have more than doubled since reaching a low of $1.83 per Mcf on September 4, EIA expects any further price run-up to be limited through the remainder of the year. High storage levels and resilient domestic production are expected to keep prices around $5 per Mcf in the coming months, even as space-heating demand increases and economic conditions improve. Beyond the winter, limited demand growth constrains price increases through the forecast. The projected Henry Hub spot price averages $4.03 per Mcf in 2009 and $5.01 per Mcf in 2010.

Short-Term Energy Outlook – November 2009, at 6.

The effect of EIA's changes over the term of the Block Contract beginning November 15, 2009, and extending through December 31, 2010, increased their average forecast for the period from $4.92 per Mcf to $4.95per Mcf, or a change of less than one percent (1%). As a result, BPA believes this sustains its earlier conclusion that BPA's updated natural gas price forecast is reasonable compared to a recent history of Henry Hub spot prices and compared to what other industry experts, including EIA, are expecting.

In summary, BPA has utilized the most recent forecast of Henry Hub natural gas spot prices that BPA has performed. BPA's updated natural gas price forecast also reflects a more contemporary understanding of natural gas market fundamentals than the WP-10 natural gas price forecast. Furthermore, BPA's updated natural gas price forecast is reasonable when compared with the recent history of spot market prices for natural gas at the Henry Hub and the natural gas price forecasts of other industry experts. Moreover, BPA has reviewed EIA's most current STEO and addressed the risk of prices deviating from expectations. Therefore, BPA believes the updates made to its forecast of Henry Hub natural gas spot prices and its use as an input to the Aurora® model utilized in this analysis are reasonable.

Forward Market Sale

In BPA's view, the sale under the Block Contract meets the most conservative, yet still plausible, reading of the court's interpretation in *PNGC II* of "sound business principles" because BPA expects to accrue positive net revenues from the sale compared to its market forecast; in other words, BPA forecasts it will make more money on the transaction compared to selling the power into the short-term market. BPA does not believe either that this is a standard for discretionary sales to the DSIs required by statute, or that the court in *PNGC II* unequivocally held that this is the correct standard. However, if this is, in fact, the legally required standard, then it is met in this case.

However, some parties, including Snohomish and PPC, appear to argue that even this is not enough. These parties appear to take the position that BPA may not make a sale to a DSI at the IP rate even if such sale is forecast to result in positive net revenues compared to forecasted market revenues, if BPA could earn even greater revenues by selling the power into the current forward market. Snohomish at 1-2; PPC at 2.

First, BPA does not typically sell its surplus into the forward markets this far in advance or for a term this long. Again, a forward sale means a sale consummated *that day* for delivery sometime in the future. By definition, and especially with respect to a hydro-based system, such sales contain some element of risk. This is because a forward surplus sale would be a firm commitment, and to the extent BPA forecasted surplus did not materialize, it would be required to purchase some or all of that power for delivery to the counterparty. The costs and risks of such a forward surplus sale would not have been addressed in BPA rates, whereas the costs and risks of a BPA firm requirements sale – including the sale under the Block Contract at the IP sale – have been addressed in BPA's rate proceeding. In establishing its firm power rates BPA makes a load and resources forecast which covers its expected sales to regional customer loads – public, cooperative and federal agency customers, investor-owned utilities, and DSIs – and resource needs. In recent years BPA has moved away from making year long forward sales of its surplus, instead making a majority of its surplus sales into the spot or short-term markets much closer to the time of delivery, when hydrological conditions, load shapes, and other factors impacting BPA's inventory are clearer.

Second, BPA does not believe there is any support, in either its enabling statutes or in *PNGC I* or *PNGC II*, 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. These public customers' view appears to be based on the position that BPA is obligated by statute to maximize revenues through sales of surplus power in order to reduce preference customers' rates to the lowest possible levels. There is nothing in BPA's statutes, or Ninth Circuit case law, including *PNGC II*, supporting this position.[21] To the contrary, to the extent that BPA finds, consistent with Ninth Circuit case law, that serving DSI load benefits BPA's operations or otherwise promotes its other statutory mandates, then BPA may incur costs to serve DSI load, and allocate such costs to all its base rates, including its preference rates. See *Golden Northwest Aluminum, Inc., v BPA,* 501 F.3d 1037, 1043 (9th Cir. 2007). Further, BPA is authorized to sell as surplus power that power which is surplus after having met its contractual obligations under sections 5(b), (c), and (d) of the northwest Power Act. 16 U.S.C. § 839c(f). Thus, a sale under section 5(d) is not a sale of surplus power.

Finally, it is worth noting Alcoa has taken the position that BPA is obligated by the regional preference provisions in its enabling statutes to sell available surplus power to any DSI, at the IP rate, before such power can be sold out-of-region at market-based rates, and that *PNGC II* supports its position. See, *e.g.*, Alcoa comments dated August 3, 2009, regarding memorandum of understanding for long-term DSI service proposal, at 2;

[21] 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).

and Alcoa comments dated September 9, 2009, regarding draft 7-year power sales agreement, at 5 (Attachments C and D). While BPA disagrees with Alcoa's view of the scope of its regional preference right, and its reading of *PNGC II* with respect to that right, it is not unlikely that Alcoa – or perhaps another DSI - would seek to challenge an out-of-region long-term market priced surplus sale made in lieu of selling such power to it at the IP rate. The suggestion that BPA should simply sell into the current forward market the power it would otherwise sell to Port Townsend under the Block Contract comes with its own set of litigation risks that would need to be evaluated in the context of putting a dollar value on such a transaction.

In sum, making a long-term forward surplus sale in lieu of selling 20.5 aMW to Port Townsend, as advocated by some customers in comments, presents its own risks, is inconsistent with BPA's current surplus marketing program approach, and is not legally required, even if it may result in greater revenues compared to revenues under the Block Contract.

6. Power Reserves

Port Townsend will provide reserves to BPA under the Block Contract, as specified in the Minimum DSI Operating Reserve – Supplemental section of BPA's 2010 General Rate Schedule Provisions (referred to below as the "Supplemental Operating Reserve"), and Exhibit H of the contract. Port Townsend will provide approximately 2 MW of reserves, within a time frame, in an amount, and for a duration consistent with applicable reliability standards, and as specified by Exhibit H.

Several parties raised issues with respect to the reserve provisions in the Block Contract. PPC, SUB, and PNGC also questioned whether Port Townsend would be able to provide the reserves contemplated by the Block Contract in the event BPA calls on them, and PNGC posited the reserves may be of little value given the relatively small size of the Port Townsend load, while SUB noted that such reserves will be unavailable (and therefore worthless) in the event Port Townsend curtails its load. PPC at 2; SUB at 7; PNGC at 2. For its part, Snohomish commented that the exhibit addressing the details of reserves in the Block Contract is unclear in several respects, including the return energy provisions, and that the contract appears to provide that Port Townsend would receive compensation for providing reserves in addition to the reserves credit embedded in the IP rate. Snohomish at 2-3.

The amount and quality of the reserves Port Townsend will provide under the Block Contract are consistent with statutory requirements and BPA's established rate schedules, and BPA believes will be made available by Port Townsend if and when called on by BPA under the Block Contract. In fact, Port Townsend provided the same reserve product under the October Interim Contract that permitted BPA to interrupt deliveries of electric power to Port Townsend in the event of a power system disturbance. As such, BPA and Port Townsend implemented a test procedure to ensure Port Townsend could provide the reserves as specified. Port Townsend successfully complied with multiple tests of their provision of reserves to BPA. As such, BPA believes Port Townsend will be compliant with the reserve provision of the Block Contract when called upon by BPA.

In addition, in the WP-10 rate proceeding, BPA contemplated that the DSIs may provide a last-off-first-on reserve, but 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:

> We agree that we must consider any lack of flexibility when we value the reserve service provided by the DSIs. The fact that the DSIs may provide a last-off-first-on reserve and the fact that this reserve can be deployed a maximum of once a day may result in a smaller value for these reserves as compared to the Initial Proposal value of Supplemental Operating Reserve. We have not fully analyzed all these limitations and considerations, but due to the IOUs' point that standing ready has value; the new information provided through BPA-AL-01, Exhibit 1; and the assumption that load-based reserves would be deployed last, 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. Therefore, we propose not to de-rate the value of reserve in this rate case. (WP-10-E-BPA-36, page 21)

Even as a last-off-first-on reserve, BPA expected to call on the reserve provided by the DSIs as described below:

> BPA analyzed our contingency reserve obligation and contingency reserve deployment for FY 2008 to determine how frequently the capacity was fully used. To capture the capacity component, the contingency reserve obligation and deployment were analyzed within hour on a one minute time interval. On a minute by minute basis, the observed peak contingency reserve obligation was 752 MW and observed peak contingency reserve deployment was 599 MW during the study period. Analysis showed that the contingency reserves deployed were within 40 MW of the contingency reserve obligation nine times during the study period. The full amount of the contingency reserve obligation was deployed five times. The contingency reserve deployments that were within 40 MW of full requirements did not occur more than once a month and the duration of deployment ranged from seventeen (17) to seventy-five (75) minutes. (WP-10-E-BPA-36, page 33)

BPA expects to call upon the reserves provided by Port Townsend, if needed, at least as frequently as the reserve contemplated in the WP-10 rate proceeding.

As to the value of reserves from a small load, the compensation realized by Port Townsend is through a rate credit of $0.80 per MWh. By including the compensation in the IP rate, the amount "paid" to a DSI is directly proportional to the size of its load. If it is a large load capable of providing more reserves, the DSI will be compensated with a larger amount of dollars. If the DSI is a smaller load, such as Port Townsend, it will provide fewer reserves, but will compensated with a proportionally smaller amount of dollars.

SUB's comments with respect to the effect of a possible curtailment on the value of the reserves provided by Port Townsend are misplaced, because if Port Townsend curtails its load, providing no reserves, BPA will not be compensating Port Townsend for such reserves not provided. Compensation is provided through a 7(c)(3) rate credit, so if Port Townsend curtails, it will not be paying the IP rate and therefore will not receive a rate credit. And in any case, as noted above, Port Townsend remains obligated to keep BPA whole in an amount equal to the IP rate plus $0.80 to account for the value of the reserves not provided when curtailed, up to its take-or-pay obligation, for any curtailed power.[22]

As stated earlier, Port Townsend will provide reserves to BPA under the Block Contract, as specified in the Minimum DSI Operating Reserve – Supplemental section of BPA's 2010 General Rate Schedule Provisions, and Exhibit H of the Block Contract.

Snohomish commented that language in section 6 of Exhibit H of the Block Contract suggested BPA was considering an adder to the IP-10 rate to provide additional compensation – in addition to the credit already embedded in the rate - for any reserves it may call upon. Snohomish at 2. BPA is not proposing to adjust the IP-10 rate as a part of compensation for Minimum DSI Operating Reserve – Supplemental. The language in section 6 of Exhibit H is meant to specify how Port Townsend is compensated for providing Minimum DSI Operating Reserve – Supplemental under the Block Contact. BPA revised the referenced language to make clear that the adjustment for Port Townsend providing this reserve has already been made to the IP-10 rate determinants as part of the WP-10 rate making process.

Snohomish also commented that the Return Energy provisions in section 7 of Exhibit H of the Block Contract did not make sense because "it is unclear how Port Townsend would make use of the returned energy." *Id*. at 3. After considering the party's comment, and discussion with Port Townsend, BPA has reconsidered returning energy curtailed when BPA requested Minimum DSI Operating Reserve – Supplemental from Port Townsend. BPA has decided instead to "cash out" the energy that was to be made available to Port Townsend by BPA. BPA will credit Port Townsend an amount equal to the product of the amount of Return Energy (MWh) and the appropriate IP Monthly Energy Rate on its following Monthly Wholesale Power Bill.

[22] SUB commented that Port Townsend is not providing reserves under curtailment situations and that the $0.80/MWh reserve credit should be added back in when determining liquidated damages. After considering this comment BPA decided to add the credit back into the calculation under those circumstances and changed the contract language accordingly.

7. Other Issues

Several parties complained that BPA did not provide sufficient time for them to review the Block Contract, that BPA had provided insufficient information to evaluate the proposed transaction, that such information was not provided in a timely manner, that BPA's analysis should be subject to a hearing under section 7(i) of the Northwest Power Act, or requested that BPA meet with them to answer their questions with respect to the Block Contract. PPC at 2 (requesting meeting with BPA); NRU at 2 (requesting meeting with BPA); PNGC at 2 (requesting meeting with BPA); Snohomish at 1 (economic analysis not timely posted, too little time); SUB at 1-2, 7 (each of the foregoing complaints).

In an attempt to address the questions and concerns of it public preference customers, BPA's Deputy Administrator and certain BPA staff met with these customers on November 3, 2009. The prepared materials that BPA presented at this meeting are attached hereto. Attachment E. With respect to the amount of time allowed for comments, BPA can only note that it provided as much time as possible under the circumstances, which includes reserving enough time to evaluate comments as part of its decision-making process. Given the relatively straight-forward nature of the Block Contract and BPA's economic analysis, BPA believes customers had sufficient time to carefully evaluate the contract and BPA's analysis, and that this fact is evidenced in the generally high quality of comments received.[23]

SUB filed a comment that appears to argue BPA's analysis of the Block Contract is subject to a section 7(i) hearing under the Northwest Power Act, or that it must be subjected to the same level of scrutiny associated with a section 7(i) hearing. SUB at 7. BPA's analysis of the economic effect of a proposed contract is clearly not subject to a section 7(i) rate hearing, since BPA is not establishing rates in the Block Contract, nor could it. SUB cryptically suggests BPA is "decoupling" its forecast of benefits under the Block Contract from "the WP-07 rate setting process which includes a number of components – including loads and risks." SUB at 7. SUB appears to be suggesting that any contract BPA proposes to execute during the term of a rate period requires BPA to re-open its rate proceeding to reconcile the rate impacts of the contract to BPA's rate case final decisions with respect to, among other things, "loads and risks." *Id*. In simplest terms, BPA sets its rates to recover its forecast costs over the term of the rate period. As noted, BPA allocated $37 million in forecast costs to its base rates to serve DSI load in the WP-10 rate proceeding, which covers the term of the Block Contract. That is not to say, as is suggested by SUB, that any proposed action by BPA within the WP-10 rate period that could result in BPA incurring costs not expressly contemplated in the rate

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[23] While BPA is committed to providing reasonable opportunities for meaningful public comment on proposed DSI contracts, there is no legal requirement, under either the Administrative Procedures Act or any of BPA's enabling statutes, that BPA provide notice and comment when executing a contract with a DSI customer. See e.g. *Alcaraz v. Block*, 746 F.2d 593 (9th Cir. 1984) (APA does not apply to matters relating to contracts); *Rainbow Valley Citus Corp. v Federal Crop Insurance Corp.*, 506 F.2d 467 (9th Cir. 1974).

case requires BPA to re-open that rate case; such costs, if incurred, would be paid for through cash reserves, planned net revenues for risk, or other risk mitigation tools such as the cost recovery adjustment clause.

SUB also asserts that the Block Contract will "create job losses throughout the region." SUB at 1. SUB provides no evidence to support this extraordinary conclusion, but it seems unlikely that BPA's decision to sell up to 20 aMW to a small paper mill for 14-months (from a system that generates over 9,000 aMW annually), at a rate forecast to be above the market over the term of the contract, will lead to any job losses whatsoever. Even in the event that SUB is right, and BPA's forecast of market prices is too low, or BPA's forecast that it will not be required to make additional purchases to serve Port Townsend is wrong, and that BPA will incur some cost in excess of the costs already allocated to BPA's WP-10 base rates for DSI service - an extremely low probability event - the impact on the preference rate of such a result would be miniscule, if there would be any impact at all.[24]

SUB asserts that BPA has "failed to address risk" and describes scenarios, mainly related to market prices and the availability of surplus on BPA's system, under which BPA may incur costs to serve Port Townsend (SUB at 4-5). In fact, each of SUB's concerns have been examined by BPA as part of its economic analysis of the Block Contract, as described in this record of decision. BPA has simply come to different conclusions based on its view of the market. In addition, the Block Contract itself, as described above, contains a number of risk mitigation provisions. The residual risk that BPA may incur costs to serve Port Townsend resulting in an increase to the rates paid by SUB is very small, and if it were to materialize, would likely result in no, or a negligible, increase in SUB's rates.

PNGC suggested that the contract be amended to cap BPA's exposure to market purchases equal to the IP rate, and to allow BPA to remarket power under the Block Contract in the event market prices exceed the IP rate by some "reasonable margin," which PNGC noted could be as little as ten percent above the IP rate. PNGC at 2. PNGC's proposal would fundamentally deprive Port Townsend of the benefit of its bargain and is not commercially reasonable, and would be highly unfair to Port Townsend which according to BPA's forecast has agreed to purchase power from BPA for a price, on average over the term of the Block Contract, which will be above market. Certainly, Port Townsend has its own reasons for entering into this transaction, and presumably believes purchasing from BPA, even at a small premium to market, is in its own best interests. If market prices fall lower than forecast by BPA, Port Townsend is locked into paying an even higher premium to market. Under PNGC's proposal, if prices rise, Port Townsend would also face the possibility of losing its BPA power supply. BPA does not find this to be a reasonable or business-like proposition, or one that is required

[24] If the Block Contract results in financial losses to BPA, there would be no rate impact to BPA's customers until at least October 2011. Rates are set for FY 2010-2011 and the probability of the cost recovery adjustment clause triggering in FY 2011 is near zero.

by *PNGC II*. In any case, BPA believes its economic analysis of the Block Contract is conservative, so that PNGC's proposals are not only unfair, but unnecessary.

SUB commented in an earlier process that BPA must resolve any lookback amounts owing by the DSIs, including Port Townsend, associated with the Court's remand in *PNGC I*. See SUB comments dated September 9, 2009, re "Draft Seven-Year Agreements: Alcoa & Columbia Falls Aluminum Company", at 6. BPA believes that final decisions by BPA in connection with that remand are unrelated to BPA's decision to enter into the Block Contract, and that nothing in the Block Contract precludes BPA from seeking restitution from Port Townsend in connection with the remand if, in fact, that is the outcome on remand, or in later raising rates to Port Townsend to effect such restitution. Final resolution, including judicial review, of the issues on remand in *PNGC I* are likely to be contentious and time consuming, and BPA sees no good reason to delay entering into a new Block Contract with Port Townsend until that process is completed.

8. PNGC II

On August 28, 2009, the Ninth Circuit issued its opinion in *Pacific Northwest Generating Cooperative v. BPA*, Slip Op. 09-70228 (August 28, 2009) ("*PNGC II*"). BPA reads *PNGC II* as requiring that if the Administrator exercises his discretion to serve a DSI customer, the decision to serve must be consistent with "sound business principles," meaning in this context that the benefits to BPA of serving the DSI load must equal or exceed BPA's cost of serving the load during the period of service or, if they do not, there must be a demonstrated and realistic prospect that the short-term net cost of providing DSI service will be offset by positive net benefits of future DSI service. BPA refers to the *PNGC II* requirement herein as the "equivalent benefits test".

As noted, the DSIs disagree with BPA's reading of *PNGC II*. Indeed, the DSIs' position comports with BPA's view of its statutory mandate to assure the Pacific Northwest, including the DSIs, an adequate, efficient, economical and reliable power supply. However, inasmuch as BPA believes the most sustainable reading of *PNGC II* is that service to the DSIs must be conservatively measured against an equivalent benefits test, BPA has constrained its consideration of Port Townsend service options to those that will satisfy that test. Absent the equivalent benefits test, BPA would have considered other, longer-term service options.

As indicated earlier, Port Townsend expressed concern that the relatively short-term of the Block Contract "impairs the long-term planning so important to an industrial customer such as Port Townsend." Port Townsend at 1. Citing BPA's letter that accompanied publication of the draft Block Contract for public comment, Port Townsend commented that it appeared BPA was taking the position that *PNGC II* prohibits a power sale to a DSI "unless the price is above the market price of power for the time period the power is offered," and that they believed such a reading is at odds with the plain language of that opinion. *Id*. at 2. Alcoa made a similar comment, citing extensively from *PNGC II* to support its position that BPA "need not conduct an accounting analysis that demonstrates that the economic benefits of the contract are equal to, or exceed the cost of providing service" to a DSI. Alcoa at 1-2. CFAC echoed this position, and also commented that BPA needed to take into account transmission costs it would avoid by making the sale to Port Townsend in lieu of selling the power into the market. CFAC at 1.

Taking the opposite position, the PPC/ICNU comments state that BPA's approach "appears to recognize that the Ninth Circuit's recent decisions have established that BPA is authorized to serve the DSIs only if the agency demonstrates that doing so is calculated to financially benefit the agency." PPC at 1. PNGC agrees with and adopts the PPC comments.

Before addressing the more fundamental issue of the meaning of *PNGC II*, and whether the equivalent benefit test is correct, we will address the subsidiary comments raised. With regard to the concerns expressed by Port Townsend, BPA understands, and is sympathetic with, the fact that long-term planning by Port Townsend is impaired by the short-term nature of the proposed contract. If Port Townsend is going to make capital investments, it needs reasonable certainty as to their future recovery. BPA's proposal does not allow that reasonable certainty, unless Port Townsend can recapture their investments in the short period of the contract, and BPA has no basis to deny Port Townsend's assertion that the time period of the contract is too short in that regard. However, BPA's analysis, as discussed in this ROD, looks into the future to see where the breakpoint is for purposes of satisfying the equivalent benefits test, which BPA forecasts is a 14-month contract.

With regard to the test itself, BPA did not mean to state or imply that benefits must exceed costs. Rather, as BPA reads *PNGC II*, it is sufficient if benefits equal or exceed costs. As to the demonstration of benefits, BPA agrees with Alcoa and does not believe that an "accounting analysis" is necessary to quantify the costs and benefits. However, certain costs and certain benefits can be reasonably quantified, and in that case it is reasonable to do so. BPA has presented that quantification in this record of decision. In the case of certain other benefits whose values are a matter of judgment, such as for example a litigation waiver or a waiver of a right to argue certain positions, we are not foreclosing such valuations, and did not foreclose them.

BPA's Reading of PNGC II

PNGC II unequivocally requires that a decision to serve a DSI customer be consistent with sound business principles: "Given that BPA is not obligated to sell to the DSIs and that its actions are generally reviewable under the 'sound business principles' standard, it follows that a decision by BPA to enter into a contract with a DSI, like other nonobligatory contractual decisions made by the agency, *see APAC*, 126 F.3d at 1171, must also conform to the 'sound business principles'" standard.'" *PNGC II*, Slip Op. at 11972. In terms of what is demanded by that standard, the following (*PNGC II*, Slip Op. at 1989-90) and other statements in the Court's decision leave an overall and lasting impression that benefits must approximate or exceed costs:

> In short, neither the record in this case nor the record in PNGC contains any financial or other business analysis or evidence to support the agency's assertion that future benefits to the agency are (a) likely or (b) sufficiently large to make the decision to give $32 million away a sound business decision.

While that passage uses the word "or" between (a) and (b), we do not believe the Court would divorce the two. In other words, if the benefits were likely but minimal, or huge but unlikely, the tenor of the Court's decision causes BPA to believe that would be insufficient to satisfy the equivalent benefits test.

The Court elsewhere analogizes DSI sales to the incurrence by a utility of a non-necessary expense. *PNGC II,* Slip Op. at 11980, citing *McCarthy v. Middle Tenn. Elec. Membership Corp.*, 466 F.3d 399 (6th Cir. 2006). In the context of providing power at the lowest cost consistent with sound business principles, if the DSI sale comes at a net cost, with the consequence that other customers' rates are increased, *PNGC II* appears to indicate that sound business principles would be violated. *PNGC II,* Slip Op. at 11980.

That conclusion is bolstered by the Court's discussion of parties' arguments that under the sound business principles, it would never make sense to sell power at the IP rate when market rates exceed that rate. The Court disagreed, but did so in a fashion that indirectly reinforced the equivalent benefits test, as BPA has described it above (benefits to BPA of serving the load must equal or exceed BPA's costs of serving the load during the period of service or, if they do not, there must be a demonstrated and realistic prospect that the short-term net cost of providing DSI service will be offset by positive net benefits of future DSI service). The Court stated:

> We can envision several situations in which BPA might reasonably conclude that a below-market rate sale to the DSIs is a sound business decision. First, as the court alluded to in PNGC, BPA's governing statutes likely require it to offer power within the Pacific Northwest at established rates before the agency may sell power outside the region. If so, BPA might reasonably enter into a contract with the DSIs at the IP rate so as to "free up power to sell outside the Pacific Northwest."
>
> Second, BPA has asserted that the physical sale of power to the DSIs has indirect benefits that might offset a below market rate sale. For example, BPA noted in its letter explaining its justifications for the amended contract with CFAC that "DSI loads have historically benefitted BPA by taking power in relatively flat blocks that require little or no shaping; they have taken power from BPA at light load hours, when power has historically been difficult to market; and they have provided the Administrator with additional power reserves." These and other non-financial benefits to BPA could very well justify a less-than-market rate sale, but they have no direct application when, as here, BPA is not in fact physically selling power to the DSIs.

> Third, a soundly run business might reasonably offer a large customer a short-term discount with the expectation that the customer's future business at higher prices will more than make up for the short-term loss of revenue. Similarly, a reasonable business might offer a short-term discount to a customer in order to diversify its customer base or to offload unused capacity."

PNGC II, Slip Op. at 11972-973 (footnotes and citations omitted).

With regard to the first scenario, freeing up power to be sold outside the Northwest, two observations are in order. First, *Kaiser Aluminum & Chemical Corp. v. BPA*, 261 F.3d 843 (9th Cir. 2001), establishes that where BPA has a rate for surplus power sales that provides for the sales at a market rate, regional preference is satisfied if the power is made available first in the region at the same rate it could be sold for out of region. That means that if a DSI is willing to pay the higher rate, it would be entitled to the power. However, in that case, there would be equivalent benefits because DSI revenues and lost opportunity cost would be equal. Second, when the Court speaks of "reasonably" entering a DSI contract to free up power for sale outside the region, there is no indication that the Court would find the contract reasonable if the DSI contract resulted in a lost opportunity cost to BPA relative to out-of-region sales revenues.

In the second scenario, where the Court speaks of certain benefits such as sales in flat blocks possibly justifying a less-than-market rate sale, BPA reads the Court's opinion as indicating that the DSI revenues plus the other benefits must equal or exceed the lost opportunity costs of a less-than-market rate sale. In other words, the Court, while not requiring an accounting analysis, would at least require the Administrator to opine that the DSI revenues and listed benefits equal or exceed the costs, and to state why.

Finally, in the third scenario, the Court is explicit that a short-term discount could be justified if "higher prices will more than make up for the short-term loss of revenue." That all but says benefits must match costs so that there is no net cost over time. As to diversifying BPA's customer base, the Court rejected BPA's widespread use arguments in *PNGC* I so it is difficult to envision the Court allowing BPA to ascribe any real value to this. And, certainly, implicit in the Court's reference of a sale to "offload unused capacity" is the sense that the sale is the best, if not the only, economic use of the otherwise unused capacity. However, BPA is not in that situation.

BPA Believes Equivalent Benefits Test Is Inconsistent With BPA's Enabling Statutes

As indicated, BPA has structured the Block Contract to comport with its reading of what the Court has required in *PNGC II,* a reading that Port Townsend and Alcoa argue is wrong or overly conservative. BPA is not persuaded that the opinion can reasonably be interpreted in the fashion advanced by Alcoa and Port Townsend. However, BPA does believe *PNGC II* errs by constraining the Administrator's discretion to serve DSI customers to a degree that is not in concert with BPA's enabling legislation. The Northwest Power Act expressly provides that one of BPA's key missions is "to assure the

Pacific Northwest of an adequate, efficient, economical, and reliable power supply, . . ." 16 U.S.C. § 839(2). This purpose encompasses all BPA customers, including direct service industry customers, investor owned utilities, and public body and cooperative customers (preference customers). It is true that Section 5(d)(1)(B) of the Northwest Power Act authorizes, but does not require, the Administrator of BPA to sell power to DSI customers once their "initial" contracts under the Act terminate. 16 U.S.C. § 839c(d)(1)(B); *PNGC I*, 550 F.3d at 866. It is equally clear that by referring to an "initial" contract Congress envisioned the potential for continuing DSI sales beyond expiration that contract.[25] Section 5(d)(1)(B) requires only that "[s]uch sales shall provide a portion of the Administrator's reserves for firm power loads in the region." 16 U.S.C. § 839c(d)(1)(B). Section 5(d) does not otherwise mention, let alone require, that such sales shall provide other benefits to BPA or the region or be subject to a strict cost-benefits analysis that would seemingly preclude service in all but a few narrow sets of circumstances.

The rate charged to DSI customers further indicate that Congress intended that sales to DSI customers beyond the "initial" NWPA contract would be the rule, rather than the exception. When the Administrator exercises his discretion to sell power to DSIs under section 5(d)(1)(B), the rate for such sales must be established pursuant to section 7 of the Act. 16 U.S.C. § 839c(a)("All power sales under this Act . . . shall be at rates established pursuant to section 7."); *see also PNGC I*, 550 F.3d at 869. For the period prior to July 1, 1985, but only for that period, section 7(c) of the Act required the IP rate to recover the cost of resources the Administrator determined were required to serve the DSI load. 16 U.S.C. § 839e(c)(1)(A); *see also* H.R. Rep. No. 96-976, 96th Cong., 2nd Sess., pt. 2, at 36 (1980). In other words, prior to July 1, 1985, the rate was based on cost of service. After July 1, 1985, however, section 7(c) requires that the IP rate shall be based upon the Administrator's rates to his public body and cooperative customers (preference customers) and the typical margins they include in their rates to their retail industrial customers, adjusted for certain specified factors, including the value of the reserves the sales provide the Administrator. 16 U.S.C. §§ 839e(c)(2), 839e(c)(3); *see also* H.R. Rep. No. 96-976, at 36. Consequently, when the Administrator now exercises his discretion to sell power to DSIs under section 5(d)(1)(B), the sale must be at the section 7(c) IP rate that is linked to BPA's cost of serving preference customers, not a rate tied to market, specific resource purchases, DSI cost of service, or benefits other than reserves. In other words, for sales beyond 1985, Congress specified that DSIs be served at a rate that is roughly in parity with rates paid by industrial load served by preference customers. It is not clear why the Court appears to believe that Congress would design a rate to achieve such parity and also intend that it be used only in limited and narrow circumstances, as required by *PNGC II*.

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[25] Not to belabor the point but Webster's II New Riverside Dictionary defines "initial" as "of, being, or happening at the beginning." Random House College Dictionary similarly defines "initial" as "of or pertaining to the beginning; first." Roget's Thesaurus proffers the following synonyms for "initial": "first, starting, beginning, opening, commencing, primary, introductory, incipient, initiatory, inaugural, maiden; original, germinal, primal." Recommended antonyms are "last, ultimate, ending, final, closing, concluding, terminal."

Notwithstanding the Administrator's authorization to serve and this clear statutory expression that the rate for DSI service is linked to the rate for service to BPA's preference customers, the *PNGC II* opinion effectively mandates that the Administrator can only serve the DSIs if he can do so at no net costs, *i.e.*, in a way that results in no differential between the cost of serving the DSIs and the revenues resulting from service at the statutory section 7(c) IP rate. *PNGC II*, Slip Op. at 11989-90. In other words, if serving the DSIs and application of the statutory IP rate means that some costs of serving the DSIs would not be recovered through the section 7(c) IP rate, *PNGC II* forbids the Administrator from serving the DSIs unless he can show that those costs of service are offset by equal or greater benefits resulting from the service. In so doing, BPA is concerned that *PNGC II* trumps the statutory rate directive in a manner that, for the reasons next explained, has no basis in law, and improperly undermines the Administrator's authority under the Northwest Power Act "to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply, . . ." 16 U.S.C. § 839(2).

PNGC II relies upon a misreading and misapplication of "sound business principles" to arrive at its conclusion. The Court posits that (a) BPA's discretionary actions "are generally reviewable under the 'sound business principles' standard," *PNGC II* Slip Op. at 11972; (b) sound business principles means DSI service should come at no net cost to BPA: and (c) the Administrator cannot serve the DSIs if benefits do not equal or exceed net costs of service. *PNGC II*, Slip Op. at 11972, 11974.

However, in developing this logic, the Court appears to confuse statutory rate setting directives, which reference "sound business principles" with BPA's decisions regarding service to DSI customers, which are not circumscribed by such references. The Court states:

> In sum, we hold that BPA's voluntary decision to contract with the DSIs, like its other non-obligatory contractual choices, must conform to the congressionally imposed requirement that the agency act in a manner "consistent with sound business principles." *See* 16 U.S.C. §§ 838g; 839e(a)(1); 825s. The mere fact that BPA has chosen to contract with a DSI at the statutorily authorized IP rate does not insulate the decision to contract from review under the "sound business principles" standard. (Footnote Omitted.)

PNGC II, Slip Op. at 11975; *see also id*. at 11980. The first two references are to ratesetting, not a decision to serve or the incurrence of costs. Rate decisions and power service decisions are entirely separate in the Act, *compare* 16 U.S.C. § 839c (sale of power) *with* 16 U.S.C. § 839e (rates), and for purposes of what final actions are subject to judicial review, *compare* 16 U.S.C. § 839f(e)(1)(B)("sales, exchanges, and purchases of electric power under section 5") *with* 16 U.S.C. § 839f(e)(1)(G)("final rate determinations under section 7"). Section 7(a)(1) of the Northwest Power Act provides that when the Administrator sets rates for power and transmission "[s]uch rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, . . ." 16 U.S.C. § 839e(a)(1). This directive applies to all BPA rates, not just rates for DSI service.

Moreover, this statutory provision is not, as *PNGC II* determined, a directive that should be transported from the rate directive setting of the Act to which it explicitly applies and then applied to require that decisions *to sell* power be subject to identical standards. Ratemaking and power sales are two distinct activities, each of which has its own distinct requirements. The directive is limited to the establishment of rates to recover costs, *costs which have already been and will be incurred*, and to recover them consistent with sound business principles. Thus, the directive is explicit and limited, requiring that rates be set in a manner that underscores the importance of BPA recovering its cost in a manner consistent with assuring that BPA's treasury repayment obligations in full and on time. This reading is borne out by subsequent language in the same sentence of section 7(a) that refers to rates recovering "the other costs and expenses incurred by the Administrator pursuant to this Act and other provisions of law." 16 U.S.C. § 839e(a). As the Court observed in *Golden Northwest Aluminum, Inc. v. BPA*, 501 F.3d 1037, 1052-53 (9th Cir. 2007), this ratesetting requirement "presupposes that BPA knows its costs or, at the very least, that it estimates them 'in accordance with sound business principles.'" Section 7(a) takes recovery of costs, regardless of how or when they were incurred, as a fundamental precept of rate making. The provision has absolutely nothing to do with, and is inapplicable to, decisions regarding sales to statutorily identified customer classes, or for that matter, sales of surplus power.

Even if section 7(a) could somehow be seen as applying to a decision to serve, the more specific language of section 7(c) would govern. Congress addressed section 7(a) in the context of the more specific rate directives, including section 7(c), as follows:

> Section 7 of the legislation sets out the requirements BPA must follow when fixing rates for the power sold its customers under this legislation. *Subject to the general requirements (contained in section 7(a)) that BPA must continue to set its rates so that its total revenues continue to recover its total costs, BPA is required by the legislation to establish the following rates . . . [preference customer, exchange, DSI, other rates listed]*

H.R. Rep. No. 96-976, 96th Cong., 2nd Sess., pt. 2, at 36 (1980)(emphasis added). The import of this is that specific rate directives, including section 7(c), are not overridden by section 7(a) unless and, then, only to the extent necessary to assure total cost recovery. No question existed in *PNGC II* that DSI service would somehow jeopardize total cost recovery by BPA. Indeed, BPA's cash reserves dwarfed the cost incurred by BPA to provide DSI service. As to the rates themselves, BPA established the rates to recover the costs of the monetary benefits to the DSIs.

So, too, section 9 of the Transmission System Act of 1974, 16 U.S.C. § 838g, also cited by the Court, deals with ratesetting, but only ratesetting. It includes language that BPA's charges for the sale of power and transmission shall be established based on a number of factors, including "with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles." *Id*. Here, again, this is a directive dealing with the setting of charges, not with decisions by the Administrator whether to sell power. In any case, even if this language has any application to DSI ratesetting, it must be reconciled and harmonized with the very specific language of section 7(c) concerning what costs the DSI rate is to recover, not used as a basis to override it. As indicated, BPA is very concerned that *PNGC II* effectively trumps the section 7(c) directive by applying these general "sound business principles" ratesetting references to the Administrator's service decisions.

In *Cal. Energy Comm'n v. BPA*, 909 F.2d 1298, 1307-08 (9th Cir. 1990), the Court rejected claims that a BPA intertie access policy must be rejected because it failed to maximize BPA returns. Reviewing the language in 16 U.S.C. § 838g that rates be set "with a view to encouraging ... the lowest possible rates to consumers . . ." the Court observed with some prescience:

> nearly every action by BPA has some arguable impact on future rates. If the strict interpretation of the "lowest possible rates" standard advanced by DSI[] were accepted, the discretion that Congress vested in the Administrator would be eliminated.

Id. The Court in *Cal. Energy Comm'n*, clearly recognized in the preceding passage that a revenue maximization test would inappropriately rob the Administrator of the discretion afforded him by Congress. *PNGC II* appears to swing full tilt in the other direction, inconsistently imposing a rigid cost/benefit test that all but eliminates the Administrator's discretion.

In sum, the statutory requirements that BPA "establish" or "periodically review and revise" or "fix and establish" its rates "at the lowest possible rates to consumers consistent with sound business principles" cannot be read as concerning anything more than just that, the establishment of rates and the recovery of costs that have been and will be incurred. 16 U.S.C. § 838g; 16 U.S.C. § 839e(a)(1). The rates can be no lower in total than would be consistent with sound business principles so as to assure total cost recovery. In addition, rates are to be established to "recover, in accordance with sound business principles, the costs" borne by BPA. 16 U.S.C. § 839e(a)(1). Recovering the costs is, however, a matter separate from the incurrence of the costs, including through decisions to serve.

PNGC II also relies in passing on language of section 5 of the Flood Control Act of 1944, 16 U.S.C. § 825s, which provides that in marketing the output of Corp of Engineers' reservoir projects, the Secretary shall "transmit and dispose of such power and energy in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles . . ." Here, again, this reference to lowest possible rates to consumers consistent with sound business principles cannot serve to override the specific directive of Northwest Power Act section 7(c) or the authorization to serve in section 5(d). Even as a marketing matter, this language supports service to the DSIs—widespread use of power—rather than negates it. If *PNGC II* is to be read as saying that there can be no DSI service if it comes at a net cost, then the Flood Control Act language should apply in equal fashion to all service decisions since all consumers are referred to in section 5 of the Flood Control Act of 1944. That would mean that if the power could be sold at market, such that other consumers' rates could receive a greater revenue credit and so have lower rates, that is what BPA should do. But that makes absolutely no sense since there is no basis in the language to elevate one class of regional customers over another in terms of lowest possible rates. Also, the *Cal. Energy Comm'n* case rejected that very approach. The power marketing administrations do not operate on a profit-making basis, but must balance a number of considerations.[26]

Finally, *PNGC II* references in passing section 9(b) of the Northwest Power Act. That section requires that the "Secretary of Energy, the Council, and the Administrator shall take such steps as are necessary to assure the timely implementation of this Act in a sound and business-like manner." 16 U.S.C. § 839f(b). As the legislative history makes clear, the purpose of this provision was to recognize the respective responsibilities of the Department and the Administrator, so that "Bonneville cannot be delayed in its activities while these [DOE] officials review contracts, budgets, labor agreements, and other matters" and the legislation be "carried out effectively and in a timely manner." Cong. Rec. H 10685 (November 17, 1980)(Remarks of Rep. Dingell). A requirement to take such steps as are necessary to assure the timely implementation of the Act in a sound and business-like manner goes to, as it says, timely implementation, and cannot be read to say that every decision, discretionary or otherwise, of the Administrator must be consistent with "sound business principles," as that term has been defined by the *PNGC II* court. Yet, that is precisely what *PNGC II* appears to require by setting sound business principles up as the yardstick by which to test the Administrator's decision to serve the DSIs. If section 9(b) did have the broad application evidenced by *PNGC II*, Congress need not have referenced sound business principles, as it did, in connection with the establishment of rates.

BPA has broad authority to act in a businesslike manner, but that authority rests on the Administrator's expansive contracting authority under section 2(f) of the Bonneville Project Act, 16 U.S.C. § 832a(f). That section provides:

> Subject only to the provisions of this Act, the Administrator is authorized to enter into such contracts, agreements, and arrangements, including the amendment, modification, adjustment, or cancellation thereof and the compromise or final settlement of any claim arising thereunder, and to make such expenditures, upon such terms and conditions and in such manner as he may deem necessary.

[26] Five circuits have considered whether the widespread use clause of section 5 of the Flood Control Act provides law to apply to an administrator's decisions in power marketing. Each has concluded that it does not. *See Salt Lake City v. Western Area Power Administration*, 926 F.2d 974, 979 (10th Cir. 1991); *City of Santa Clara v. Andrus*, 572 F.2d 660, 668 (9th Cir. 1978), *cert. denied*, 439 U.S. 859 (1978); *Brazos Elec. Power Coop. v. Southwestern Power Admin.*, 819 F.2d 537, 543-44 (5th Cir. 1987); *Electricities of North Carolina v. Southeastern Power Admin.*, 774 F.2d 1262, 1266 (4th Cir.1985); *Greenwood Util. Comm'n v. Hodel*, 764 F.2d 1459, 1464-65 (11th Cir.1985).

The Congressional intent behind this language was "to enable the Administrator to employ business principles and methods in the operation of a business enterprise . . ." H.R. Rep. No. 777, 79th Cong., 1st Sess., 3 (June 21, 1945). The Northwest Power Act extended section 2(f)'s expansive authority to enter into contracts under that Act.[27]

With the passage of the Northwest Power Act, the Administrator's responsibilities were significantly expanded. The broad grant of contracting authority to enable the Administrator to employ business principles and methods was incorporated into BPA's statutes as a means to enhance BPA's ability to implement its statutory authorities, not to restrain them.

Earlier cases illustrate the important distinction of bringing sound business principles into play when Congress has not clearly addressed a matter and it is necessary to fill the gaps, versus the situation where Congress has specifically authorized the Administrator to take an action, such as serve DSI customers. In cases such as *Bell v. BPA*, 340 F.3d 945 (9th Cir. 2003)(buying out contractual obligations), *Aluminum Co. of America v. BPA*, 903 F.2d 585 (9th Cir. 1989)(wheeling non-Federal Power), and *Dep't of Water & Power of the City of Los Angeles v. BPA*, 759 F.2d 684, 693 (9th Cir.1985)(intertie access), the statute did not address the matter at hand and there was, in the words of *Association of Public Agency Customers v. BPA*, 126 F.3d 1158, 1170 (9th Cir. 1997)(sale of transmission to DSIs), a gap to fill with "how best to further BPA's business interests consistent with its public mission." Indeed, the Northwest Power Act does not address the monetization of contracts, so there again, as in *PNGC I*, it is appropriate to determine what is prudent and businesslike. In other cases, the issues dealt with rates, and a legitimate question arose as to compliance with the sound business principle rate language. *See, e.g., Public Power Council, Inc. v. BPA*, 442 F.3d 1204, 1206 (9th Cir. 2006)(rate adjustment). Here, however, where the question in the first instance is whether the Administrator may choose to serve the DSIs—a contractual decision that then leads to the separate question of monetization at issue in *PNGC II*—Congress authorized but did not require the Administrator to provide service to DSI customers. 16 U.S.C. § 839c(d)(1)(B). There is simply no reason to look to section 2(f) or 9(a)when reviewing the Administrator's decision to serve DSIs, for the simple reason that DSI sales are authorized and offered under section 5(d)(1)(A), not section 2(f), 9(a) or any other provision of BPA's enabling legislation.

BPA's concern that the *PNGC* panel fundamentally misreads the statutory references to "sound business principles" as having expansive sweep is confirmed by the following passage:

> Even more relevantly, the Sixth Circuit, in interpreting *a statutory directive very similar to the statutory requirements at issue here,* concluded that there was sufficient law to apply. *See* <u>*McCarthy v. Middle Tenn. Elec. Membership Corp.*, 466 F.3d 399 (6th Cir. 2006)</u>. In

[27] "Subject to the provisions of this Act, the Administrator is authorized to contract in accordance with section 2(f) of the Bonneville Project Act of 1937 (16 U.S.C. 832a(f)). Other provisions of law applicable to such contracts on the effective date of this Act shall continue to be applicable." 16 U.S.C. § 839f(a).

> *McCarthy,* the Sixth Circuit held that an electric cooperative's decision to incur “non-necessary expenses,” if proven true, would “clear[ly]” violate the cooperative's statutory duty under Tennessee law to provide its “members with electricity ‘at the lowest cost consistent with sound business principles.’ “ *Id.* at 410 (citing Tenn.Code Ann. § 65-25-203).

PNGC II, Slip Op. at 11980 (emphasis added). BPA does not operate under a statutory duty to provide its customers with electricity at the lowest cost consistent with sound business principles, such that every facet of its business is reviewable under that standard. It operates under responsibilities to *set rates* as low as possible consistent with sound business principles, to *timely implement* the Northwest Power Act in a sound and business-like fashion, to *exercise its section 2(f) and 9(a) authorities* in a business-like manner, and to market some power in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles. None of the foregoing, however, can be read to mean that BPA may not take a discretionary action, such as serving DSI load, if that would increase other customers' costs. This is not how the standard has ever been applied and is not how it was ever intended to be applied. In short, the Court appears to have turned the standard on its head so that it now shackles BPA and is a basis for constraining agency flexibility rather than expanding it, as was Congress's original intent.

However, regardless of these concerns and arguments, BPA must ensure its Block Contract with Port Townsend is consistent with *PNGC II*.

9. Environmental Effects

This agreement represents a continuation of service to Port Townsend at a rate consistent with the court's decisions in *PNGC I* and *PNGC II,* and the sale will not lead to any changes in environmental effects. Further, this type of agreement is consistent with BPA's Short-Term Marketing and Operating Arrangements ROD of January 22, 1996, a copy of which is attached hereto as Attachment F.

CONCLUSION

For the foregoing reasons, BPA has signed the Block Contract on the date of this record of decision.

Issued at Portland, Oregon, this 13th day of November, 2009.

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

ATTACHMENT A

March 19, 1996

Chuck Forman
Account Executive
Bonneville Power Administration
1835 Black Lake Blvd. S.W.
Olympia, WA 98512-5623

Dear Chuck:

The BPA Power Sales Contract, Section 5(d) - Technological Allowances, provides a method to request an increase in Contract Demand for technological reasons. Port Townsend Paper Corporation has consistently invested in its facilities to meet both the needs of our customers and the more stringent environmental regulations placed on our industry. The capital improvements have been substantial without expanding the overall production. We have been switching from a chemical pulping process to a recycled fiber process.

Section 5(d) of the Power Sales Contract provides that Port Townsend Paper may request a Technological Allowance increase in Contract Demand to cover the increased power requirements associated with the improvement and modification of equipment due to changes in technology.. Addition of environmental protection equipment is also covered by the Technological Allowance provision.

Attached is a list of the major equipment additions and modifications at the Port Townsend facility. Port Townsend Paper Corporation requests a Technological Allowance increase in Contract Demand in the amount of 3.818 MW to cover the environmental protection load and the improvements implemented at the plant as shown on the attached list. This would make our Contract Demand 20.42 MW and would allow us to purchase this additional electricity from BPA rather than having to buy it from another supplier.

Per our discussion, it is understood that BPA will evaluate this request even though the specified submittal date of February 1 has passed and will respond within 60 days as provided in the Power Sales Contract. Port Townsend Paper appreciates your review and consideration of this request and is willing to meet to discuss any aspect of this request at your convenience.

Sincerely,

Bruce McComas

Bruce McComas
Manager: Power, Recovery,
Utilities, Pulping & Recycle
Port Townsend Paper Corp.
P.O. Box 3170
Port Townsend, WA 98368

Port Townsend Paper Corp
Technological Improvements
Equipment list

Equipment Type / Project Name	Quantity	date installed year	Hp	Increase Demand Requirements MW	
Environmental Control					
Turbotac Scrubber					
2 air compressors		**1987**	600	0.312	
scrubber & quench pumps			20	0.010	
Additional pressure drop			250	0.130	
Precipitators for Recovery Boiler		**1992**	175	0.091	
Total for Environmental control				**0.544**	**MW**
OCC Recyling Plant	**Quantity**	**1996**			
Electric motors, Hp					
5	4		20	0.010	
6	1		6	0.003	
7.5	3		22.5	0.012	
10	8		80	0.042	
15	8		120	0.062	
25	4		100	0.052	
30	3		90	0.047	
40	3		120	0.062	
50	7		350	0.182	
60	1		60	0.031	
75	6		450	0.234	
100	6		600	0.312	
125	11		1375	0.715	
200	3		600	0.312	
300	1		300	0.156	
500	1		500	0.260	
1500	1		1500	0.781	
Total for OCC Recyle Plant				**3.275**	**MW**
Total Increased Demand				**3.818**	**MW**

ATTACHMENT B

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

January 29, 1997

Contract Demand
Tech. Increase = 20.5 mw

In reply refer to: PSW/700

Mr. Bruce McComas
Power, Recovery and Utilities Manager
Port Townsend Corporation
P.O. Box 3170
Port Townsend, WA 98368-3170

Dear Bruce:

The Bonneville Power Administration (BPA) has reviewed your letter dated March 19, 1996, requesting a technological allowance to increase contract demand by 3.82 megawatts (MW). Section 5(d) of Port Townsend Paper Corporation's Power Sales Contract, Contract No. DC-MS79-81BP90347 (PSC) with BPA allows for, subject to provisions therein, increases in contract demand for technological reasons other than plant expansion.

Based on your letter and my subsequent on-site review of equipment additions, BPA has determined that the addition of equipment associated with the substitution of recycled fiber for chemically derived fiber and the addition of environmental protection equipment is in accordance with the PSC provisions for a technological allowance. Port Townsend Paper is hereby granted a technological allowance of 3.9 MW.

The technological allowance is effective at 2400 hours on September 30, 1996. Enclosed for your signature are two signed originals of Exhibit C, Revision No. 1, reflecting the increase in contract demand from 16.6 MW to 20.5 MW. Please return one signed original to me at the above address.

Feel free to call me at 503-230-5831 if you have questions.

Sincerely,

Charles W. Forman Jr.

Charles W. Forman Jr.
Account Executive

Enclosure

ATTACHMENT C

August 3, 2009

Allen Burns D-7
Acting Deputy Administrator
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

Re: DSI Long-term Service

Dear Allen:

Thank you for the opportunity to comment on long-term service to BPA's last remaining direct service industrial customers (DSIs) and the draft proposed term sheet as described in your letter directed to regional customers, stakeholders and interested parties, dated July 17, 2009. Alcoa Inc. ("Alcoa") appreciated the opportunity to discuss DSI contract issues with other BPA customer groups at BPA's June 8, 2009 public meeting and appreciates BPA's efforts to put in place a long-term contract to address the Ninth Circuit's decision in *PNGC v. BPA.* While issues will likely arise during the formulation of final contract which will require resolution, we think the term sheet represents a fair effort by BPA to balance the interests of the DSIs with the interests of BPA's other customers within the discretion granted BPA by the Court in *PNGC.*

At the outset we think it is important to note that the *PNGC* decision grants BPA the authority to serve the DSIs, the Court also recognized that Section 7(c) of the Northwest Power Act determines how the rates to the DSIs are to be developed. That section provides

> "The rate or rates applicable to direct service industrial customers shall be established—
>
> for the period beginning July 1, 1985, 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."

A comparison between BPA's proposed service under the July 17, 2009 term sheet with the terms of service that form the basis for BPA service to consumer owned utilities' industrial customers is worth evaluating when considering whether Alcoa's terms of service and rates are equitable in relation to the retail rates charged by consumer owned utilities to their industrial consumers in the region. The comparison reveals that industrial consumers of publicly owned utilities will receive more favorable terms, at more favorable rates than the two remaining aluminum DSIs would receive under BPA's proposed term sheet:

	DSIs	Consumer Owned Utilities' Base Service for Their Industrial Customers
Conditions	Service linked to market Power Prices	None
Quantity	2/3 of historic load	100% of historic loads
Price	IP RATE = $34.6/MWH at 100% LF	PF Rate = 27.4/MWH at 100% LF
Term	7 years.	20 years.
Quality	Partially interruptible to preserve firm loads including consumer owned utility industrial loads	Firm

Alcoa makes this comparison to give some perspective to the campaign that consumer owned utilities and their industrial customers are waging against the compromise contract that BPA has proposed. We recognize that many of BPA's preference customers will urge BPA to end all power supply service to Alcoa. Many will argue that providing electric power service to the DSIs will unfairly raise rates to other customers and thereby increase the loss of jobs elsewhere in the region. Alcoa loads are located within the service territories of consumer-owned utilities and have been served by BPA resources longer than many industries that will continue to have all of their electricity needs served with low-cost tier-1 BPA power through those utilities in the future. Of course DSI loads have been in a substantial decline for the last decade. During the same period, preference loads have grown. Thus, increases in BPA power purchases are required to meet growing preference customer loads, not diminishing DSI loads.

Moreover, more than one-third of Alcoa's production costs are made up of power costs. There is no evidence on the record that any other major industry in the Northwest is as electricity dependent as the aluminum industry. As proposed, the maximum impact on BPA costs for purchasing the 320 MW needed to operate 2 of the 3 potlines at Intalco would be capped at $70 million per year. This represents an impact of about $1.20/MWh on rates to all of BPA customers, and the likely impact will probably be less since BPA will probably be able to make purchases at less than the capped amount.

Assuming the worst case for impact on other customers, that is, market rates at the cap of $65/MWh; let us look at the impact of the proposal on Intalco and on other industries served by consumer-owned utilities. Without the proposed service, Intalco power rates would increase from the IP rate of $34.6/MWh to $65/MWh (88%) resulting in Intalco closure and the loss of more than 2000 direct and indirect jobs as discussed later in this letter. Rates to consumer-owned utilities would be reduced by $1.20/MWh (4%) with questionable impact on employment levels. Thus, BPA may save the Intalco jobs by offering to serve the DSI loads with adequate power at the IP rate. But there is no assurance that it could save other Northwest industries by offering artificially subsidized PF rates. Indeed PNGC's employment data introduced in the BPA WP-10 rate case reveals that many Northwest industries have closed their plants notwithstanding having electric power rates from BPA's preference customers that are substantially below Intalco's electric power rates. Therefore, we urge that BPA do what it can, within its discretion, to retain Alcoa as a 70-year power customer and retain more than 2028 direct and ndirect jobs,[1] rather than succumbing to an argument that some unknown number of jobs might be saved if BPA knowingly causes Intalco to close by failing to provide it with power at the statutorily set rate that Intalco needs to operate.

1. *Providing Industrial firm power (IP) in an amount sufficient to operate two potlines at Alcoa's Ferndale is critical to the smelters' survival.*

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As Intalco demonstrated at the June 8 public meeting, it has historically operated three potlines at its Ferndale smelter. The smelter and its related facilities were designed to achieve optimum operations with three potlines in use. Partial operation of potlines (for example, 50% of capacity or one and one-half potlines) robs the smelter of electrical efficiency and less than three potlines significantly increases unit costs due to the loss of economies of scale. Because aluminum is a worldwide commodity, Alcoa cannot recapture these lost efficiencies through increasing product prices. While Alcoa negotiated with BPA in good faith to make a one and one-half potline operation work under the January 23 draft contract, in the end, Alcoa realized that it simply couldn't plan to operate the Intalco smelter with less than two-potlines and have the smelter survive the inevitable downturns in cyclical aluminum markets. While Alcoa could achieve much greater efficiency with its historic three-potline operation, it recognizes that BPA's proposal represents a compromise, designed to accommodate the needs and desires of both its preference customers and its DSIs.

To put BPA's proposed compromise into context, it is worth recalling that the Block Sale Agreements, that are effective from 2007 through 2011, contemplate that the aluminum DSIs will receive 560 aMW of service. BPA retained the ability to convert the contract to a physical sale of power which would result in 560 aMW of sales to Intalco and Columbia Falls Aluminum Company ("CFAC") based on the reallocation of Unused Benefit Amounts due to the reassignment of Goldendale Aluminum's unused 100 aMW allocation. Intalco's share of the 560 MW total is 390 MW. Thus, BPA's proposal for 320 MW to Intalco provides less power than the conversion of the existing contract to a power sale would automatically accomplish. In the absence of a contrary agreement, Alcoa believes that BPA would be obligated to provide 560 aMW of power to Intalco and CFAC under the severability clause, contained in the Block Sale Agreement, for the remaining two-year term of the Agreement. Thus, the agreement for Alcoa to forego 70

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[1] Dick Conway and Associates, "The Economic Impact of the Intalco Works Aluminum Plant, June 2008, page 4 (finding a multiplier effect of 2.9 additional jobs for each aluminum job in Washington).

aMW of power constitutes a part of the DSIs' consideration for BPA's agreement to extend the term of the DSI power sale agreements. Alcoa appreciates BPA's willingness to propose providing Intalco a sustainable amount of power for its operations even if that amount of power is less than: a) the amount of power that BPA has historically provided to serve Intalco's 3-potline operation and b) less than the amount of power committed under the 2007-2011 Block Sale Agreement.

2. *BPA has a sufficient amount of surplus power that might be used to provide service to the DSIs to mitigate the cost of buying power for all of BPA's needs.*

The Regional Preference Act (P.L. 88-552) and the Excess Federal Power statute 16 U.S.C. §832m) and Sections 5(f) and 9(c) of the Northwest Power Act require the Administrator to provide power in excess of his firm power contract obligations to customers in the region at any rate established for the disposition of such capacity and energy. The Ninth Circuit recently held in *PNGC* that BPA must offer such power to the DSIs at the IP rate. While Alcoa recognizes that BPA has a different view of its obligations, at a time when the Northwest has surplus power, it makes little sense to export power outside the Pacific Northwest when the power could be used to meet the loads of a class of customers statutorily recognized by the Northwest Power Act.

In its preliminary work preparing for the Sixth Power Plan the Northwest Power Planning Council recognizes that the Northwest is presently surplus. They also recognize that this surplus may continue with the acquisition of renewable resources and cost-effective conservation. This is particularly the case during the current severe economic recession that has disproportionately impacted the Pacific Northwest and reduced BPA's firm loads. BPA has modified its Tiered Rate Methodology to deal with this phenomenon. During these conditions and the currently favorable market prices for power on the West coast, BPA can use its surplus power and acquire power to serve the loads of all of its customers including Intalco and CFAC with much lower net costs than was previously the case. As a result, whether, under these conditions, BPA is obligated to sell power to the aluminum DSIs, or has the discretion to do so, it would be a missed opportunity (and an abuse of its discretion) if BPA failed to use its available resources and favorable market purchases to serve the Intalco and CFAC loads.

3. *Section 3 of the Draft Term Sheet is Critical to Alcoa and Could Provide Large Benefits To the Northwest Region*

BPA's Draft Term Sheet provides for BPA to meet up to two potlines of the DSIs power requirements for the remaining two-years of the existing Block Sale Agreement with a physical power sale, provided that power can be purchased at less than $48 per MWH. BPA will provide power to the DSIs for an additional 5-year term provided that BPA can serve the DSIs at a power cost of less than $64/MWH. Section 3 of the Term Sheet provides for BPA to make an early determination of the feasibility of extending aluminum DSI power service under a new contract for an indefinite period following the expiration of the intermediate 5-year term. Alcoa appreciates BPA's willingness to consider such a follow-on term as such an extension, if it comes early enough to assure a

10-year power supply may allow Alcoa to make capital investments at the Intalco smelter that would have significant benefits not only to Intalco, its employees and the community that it serves, but also to the Northwest economy as a whole. Moreover, if BPA acts quickly, it may lock-in power prices that will permit it to serve the aluminum DSIs at the lowest feasible net cost to BPA.

A contract duration of 10 years or more would allow Alcoa to make capital investments with a sufficient period of time to amortize the cost of the capital investments. On the other hand, Alcoa recognizes that if a 10-year contract requires BPA to seek to secure the full 10 years of power to serve Intalco, then the corresponding requirement for a long-term power acquisition process under Section 6(c) of the Northwest Power Act could defer action by BPA at a critical decision point for Alcoa concerning closure of the Intalco smelter.

If BPA can promptly commit to a two-year contract with an additional 5-year term and commit to consider a possible follow-on contract under acceptable terms, aggregating 10 years, this might permit capital expenditures by Alcoa that would permit longer-term operation of the smelter. This could be accomplished by permitting Alcoa to modernize the Intalco facilities to achieve greater energy and production cost efficiencies. A 10-year contract could also enable Alcoa to make and amortize investments in greenhouse gas reduction technologies that would enable the Northwest region to better meet greenhouse gas emission reduction goals. The closure of the smelter would not count toward the achievement of the goals (presumably because policy makers realize that an equivalent amount of aluminum would be required to be produced elsewhere in the world with uncertain greenhouse gas implications).

Large benefits would accrue to Alcoa's employees and the local community if a longer-term contract term is promptly achieved. Just as a longer-term contract allows Alcoa to plan for its future, it affords employees, businesses, local government, and community organizations the same opportunity. Based on the foregoing, Alcoa urges BPA to retain Section 2 of the Term Sheet and to accelerate its consideration of a follow-on contract as to offer such a contract as early as possible after October 1, 2012, in order to optimize the chances of Alcoa making needed capital investments for its own benefit and for the benefit of the region.

4. *Intalco can provide critical regional power reserves.*

As recognized by the "Rate" recital in the draft Term Sheet, Intalco can provide significant power reserves to the Northwest region as contemplated in BPA's WP-10 power proceeding. In addition to the capacity reserves contemplated in the proposal, with the addition of necessary electronic controls, the Intalco smelter load can be varied to accommodate within-hour fluctuations from new wind generations projects in the

Northwest. These potential reserves, contemplated by the Northwest Power Act, are possible if the Intalco plant continues to operate, and are yet another way in which continued electric power service to Intalco could benefit the Northwest region.

5. *The curtailment rights under Section 9 of the draft Term Sheet are a critical term of the Agreement.*

Section 9 of the draft Term Sheet permits Alcoa to curtail deliveries twice during the term of the contract. Such a provision is consistent with historic DSI contract rights and is crucial to any take or pay contract for a cyclical industry in a commodity business.

The provision results in a balanced contract where BPA may impose take-or-pay obligations, where Alcoa's curtailment rights are limited to 2 curtailments, not exceeding 24 months in total duration and where BPA has no obligation to compensate Alcoa for the excess value of power during any such curtailment. In addition, Alcoa may not seek third-party power supplies during a curtailment, thus mitigating any risk to BPA that Alcoa might curtail in order to get lower power prices. The result is a contract that disciplines Alcoa to curtail only based on low aluminum prices that make it uneconomic to operate. Further mitigating risk to BPA is the fact that the term of the contract is of relatively short duration, making it likely that BPA would recover at least as much as the IP rate for sales of power that BPA might have due to a DSI curtailment. Alcoa urges BPA to reject any revisions to this provision of the contract and upsetting the carefully balanced rights and responsibilities embodied in this section.

6. *Section 11 of the draft Term Sheet provides BPA with additional protections and provides sufficient incentive for Alcoa not to terminate the contract.*

Section 11 of the draft Term Sheet contemplates that Alcoa must give 12-months notice of termination of the contract. This provision will allow BPA time to remarket the power if Alcoa terminates the contract and during the 12-month notice period. Alcoa is obligated to pay for power at the IP rate whether or not it takes power during the notice period. This disciplines Alcoa not to terminate the contract unnecessarily, protects BPA by giving it the opportunity to remarket or find other uses for the power. Section 8 of the draft Term Sheet, provides further protection against a frivolous or unjustified termination of the contract as following a notice of termination, Alcoa is prevented from requesting power service as a DSI from BPA. Again, the critical balance achieved in this provision between BPA's and Alcoa's interests should not be upset through revisions that might tip the balance of rights and obligations unfairly, and it a way that would make the risks of the contract too great to permit Alcoa's management to sign the contract.

7. *Section 4 of the draft Term Sheet is a critical term.*

At present, Congress has before it cap and trade legislation that will define the rights and obligations of generators, utilities and industries. The version of the legislation passed by the U.S. House of Representatives will impose very large costs on emitters of greenhouse gases. The U.S. Senate is presently considering the House version of the bill and knowledgeable observes believe that the Senate is likely to make substantial changes to the House version of the bill. Section 4 of the draft Term Sheet places the risks of future carbon taxes, greenhouse gas mitigation costs or other similar environmental or

regulatory costs on the parties who will be supplying BPA power acquired to serve Alcoa by requiring the generators to include any such costs in their contracts. The provision also imposes some risk (but a measurable risk) on Alcoa by providing that the cost of power, including such greenhouse gas mitigation expenses, must fall under the price caps in Sections 1 and 2 of the draft Term Sheet.

8. *Section 5 of the draft Term Sheet imposes unpredictable risks on Alcoa that, in the aggregate could defeat the contract.*

Section 5 of the draft Term Sheet contemplates two bases for BPA to impose on Alcoa the costs of renewable energy portfolio standards obligations or costs imposed on BPA directly for carbon taxes or charges, greenhouse gas mitigation costs or other environmental or regulatory charges: 1) recovery through rates or 2) through some other unspecified mechanism. While the provision also entitles Alcoa to terminate the contract if such costs are imposed, that right would, of course, come at the cost of closure of the Intalco smelter. Alcoa urges BPA to develop language in the contract that would eliminate or at least minimize the possibility of allowing BPA to recover presently undefined and unspecified greenhouse gas costs from Alcoa through a mechanism other than rates. BPA has ample ratemaking authority through Section 7(g) of the Northwest Power Act to fairly allocate unanticipated costs—but within the disciplined context of a contested rate case where Alcoa and other parties can evaluate the nature and cause of various costs and advocate the spreading of those costs based on equitable principles.

<u>Conclusion</u>

The preference customers have asserted in various forums that BPA violates the discretion accorded BPA by the Ninth Circuit in the *PNGC* decision if it provides power to the aluminum DSIs at less than market price. Alcoa strongly urges BPA to reject this illogic. The consumer owned utility rates are more than 26 percent lower than the rates that would presently apply to the power sold under a contract to Alcoa. The Ninth Circuit authorizes BPA to serve the DSIs at the IP rate (not to impose market prices on the DSIs) and the three regional preference statutes were clearly enacted to give preference to Northwest regional loads. To fail to serve Intalco and CFAC at the IP rate during the current severe economic recession and in the face of BPA’s surplus would not only fail to meet Congressional intent in enacting the three regional preference statutes, but would constitute an abuse of BPA’s discretion. We urge BPA to move forward with a contract that adheres to the proposal embodied in its July 17 Draft Term Sheet in order equitably to serve one of BPA’s longest-term customers (Alcoa) and to preserve the jobs that are so important to the Northwest’s economic recovery from this deep and protracted recession.

Alcoa, and the Ferndale, Washington community that has over 2000 jobs associated with the Intalco facility are grateful to BPA for seeking a middle ground that will give Intalco an opportunity to continue to operate under difficult market conditions. The provisions of the draft Term Sheet will allow Intalco to continue to provide the employment and other economic and community benefits and electric power reserves that are achieved with physical power service from BPA. It will also help the United States to preserve industrial manufacturing capability that is important to not only employment, but also to the balance-of-trade and security interests of the country.

Sincerely,

Mike F. Rousseau
Plant Manger, Alcoa Intalco Works

cc: Governor Gregoire,
NW Congressional Delegation

ATTACHMENT D

September 9, 2009

Allen Burns – A-7
Acting Deputy Administrator
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621

Re: 7-year Power Sale Agreement

Dear Allen:

Alcoa appreciates the opportunity to comment on BPA's proposed physical power sale to Alcoa's Intalco smelter. For the last several years, Alcoa has been advocating for a physical power sale to Intalco, more along the lines represented by Alcoa's historic 70-year relationship with BPA. Despite BPA's two good-faith efforts to offer Alcoa monetized power contracts, the Ninth Circuit Court of Appeals has rejected the approach. We appreciate BPA's willingness to return to a form of power contract expressly contemplated by the Northwest Power Act. While Alcoa would much prefer to receive a sufficient amount of power to serve the entire electric power load that BPA has traditionally served, we believe that the offer of 320 average megawatts of power (enough to serve two of three of Alcoa's potlines) will permit the Intalco smelter to survive and to preserve the more than 500 smelter jobs and 1,500 other jobs that are dependent upon Intalco receiving BPA's cost-based power.

Relative Rate Equity

BPA's rates to its preference customers remain amongst the lowest electric power rates in the nation. This is true despite the fact that the cost of incremental BPA power resources is much higher than BPA's average resource cost, and BPA preference customer loads have been growing. In just the period between 1999/2000 and 2008/2009, preference customer loads are expected to increase from 8,060 aMW[1] to 8,949 aMW.[2] DSI loads have declined from a high of 3,153 aMW in FY 1991 to 474 aMW in FY 2009.[3] In other words, the incremental loads responsible for driving up prices for all customers, whether preference or DSI, are the growing preference customer loads, not the decreasing DSI loads. Alcoa recognizes that BPA's preference customers would prefer to view aluminum smelter loads as incremental loads that should pay rates reflecting BPA's marginal costs

[1] *See* Bonneville Power Administration, 1998 Pacific Northwest Loads and Resources Study, Table 3 (Also available at: http://www.bpa.gov/power/pgp/whitebook/1998/.

[2] *See* Bonneville Power Administration, 2007 Pacific Northwest Loads and Resource Study, Table 9. Also available at: http://www.bpa.gov/power/pgp/whitebook/2007/.

of power. But since DSI loads are declining, and preference customer loads are increasing, and since Alcoa would receive under the 7-year Agreement, at most two-thirds of its power requirements that have historically been served by BPA, one can understand why Alcoa rejects the notion that its loads are contributing to BPA's increasing costs for meeting its growing loads. Moreover, BPA calculated, in its WP-10 power rates, currently before the Federal Energy Regulatory Commission, the rates that the Northwest Power Act establishes as the correct power rates for Alcoa's loads.

Under BPA's proposal, Alcoa will pay $34.60 per MWh for its power purchased from BPA. BPA's preference customers, on the other hand, will pay average rates (at the same load factor) that are $27.40 per MWH. Thus under BPA's proposal, Alcoa will already be paying 26% more for power than BPA's preference customers. While Alcoa recognizes that BPA's preference customers would prefer to be able to either purchase or gain all of the economic value from all of the power that BPA can produce—and that doing so would keep their rates even lower, such a result would be completely contrary to the express objective of the Northwest Power Act to provide some reasonable distribution of benefits of the federal system over all three classes of BPA's historic customers: its preference customers, the direct service industries, and the investor owned utilities (and their residential and small farm customers). The following table depicts the benefits that the BPA preference customers, and their industrial customers, derive from Section 7(b)(2) of the Northwest Power Act, and BPA's service decisions relative to the impact on DSI rates and quality of service:

	DSIs	Consumer Owned Utilities' Base Service forTheir Industrial Customers
Conditions	Service linked to market Power Prices	None
Quantity	2/3 of historic load	100% of historic loads as well as load growth
Price	IP RATE = $34.6/MWH at 100% LF	PF Rate = 27.4/MWH at 100% LF
Term	7 years	20 years
Quality	Partially interruptible to preserve firm loads including consumer owned utility industrial loads	100% firm

Moreover, more than one-third of Alcoa's production costs are made up of power costs. There is no evidence that any other major industry in the Northwest is as electricity-dependent as the aluminum industry. As proposed, the maximum impact on BPA costs for purchasing the 320 aMW needed to operate 2 of the 3 potlines at Intalco would be capped at $60 million per year for the final 5 years of the Agreement. This represents a maximum potential impact of about $1.00/MWh on rates to all of BPA customers, and the likely actual impact will most likely be less since BPA will probably be able to make purchases at less than the capped amount.

The consequences of not providing Alcoa with the proposed service are dramatically different that the consequences of doing so, even assuming the worst-case impact on the rates of BPA's customers (i.e. market rates at the cap of $58.50/MWh). Without the proposed service, Intalco power rates would increase from the IP rate of $34.60/MWh to $58.50/MWh (69%) resulting in the closure of the Intalco smelter and the loss of more than 2,000 direct and indirect jobs. BPA may save the Intalco jobs by offering to serve the DSI loads with the proposed levels of service (320 aMW) at the IP rate.
But without the proposed service, rates to consumer-owned utilities would be reduced by $1.00/MWh (3%) with no discernable positive impact on employment levels, and there is no assurance that BPA could save other Northwest industries by offering artificially subsidized PF rates. Indeed PNGC's employment data raised in its comments (TDS 090201) dated August 3, 2009, demonstrates the regrettable impact that the economic downturn has had on the Northwest. It also reveals that many Northwest industries have closed their plants notwithstanding having electric power rates from BPA's preference customers that are substantially below Intalco's electric power rates. Closing the Intalco plant would not restore employment to other regional workers.

Therefore, we urge that BPA do what it can, within the bounds of its discretion, to retain Alcoa as a 70-year power customer and retain the more than 2,059 direct and indirect jobs that would result,[4] rather than succumbing to an argument that some hypothetical number of jobs might be saved if BPA knowingly causes Intalco to close by failing to provide it with power at the statutorily set rate that it needs to operate.

Alcoa continues to believe the decision to offer electric power service to Alcoa should be made on the basis of BPA's long-term historic relationship with Alcoa, and that BPA should exercise the discretion it has been accorded by Congress to preserve both the customer diversity and jobs that such service would provide. BPA has, instead, determined that it will look for some positive net economic benefit to the region from offering a contract for the Intalco plant. Alcoa believes that such a standard is discriminatory (no other customer is required to make any such demonstration) and therefore the standard is arbitrary and capricious. Nevertheless, BPA's own economic studies demonstrate that there is a positive economic benefit from offering the contemplated service to Alcoa.[5] Alcoa believes that the 2006 and 2008 Conway Studies, previously submitted by Alcoa to BPA in DSL090058 and DSL090059, are a far better way to assess economic impact of providing electric power service to Alcoa than the "Regional Employment and Economic Study" approach. The latter approach seeks to quantify impacts on other regional employers of BPA rate decisions that the study

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[4] Dick Conway and Associates, *The Economic Impact of the Intalco Works Aluminum Plant*, June 2008, page 4 (finding a multiplier effect of 2.9 additional jobs for each aluminum job in Washington).

[5] "Summary of BPA's Use of the Regional Economic Study to Contemplate the Service Concept."
http://www.bpa.gov/power/pl/regionaldialogue/implementation/documents/2009/2009-08-28_BPAsUse-of-RegionalEconomicStudy-for-Contemplation-of-ServiceConcept-Summary.pdf

automatically (and incorrectly) ascribes to DSI service, rather than discussed herein, the more conventional economic theory that would ascribe marginal power costs to customers who are imposing load growth on the BPA.

DSI's historic benefits to BPA

Alcoa has been a BPA customer ever since Administrator Paul Raver signed a contract with Alcoa on December 20, 1939.[6] In the ensuing 70 years, Alcoa has consistently bought power from BPA. In the aggregate, the DSIs historically constituted about one-third of BPA's load and paid BPA revenues for power that permitted BPA to amortize the Federal Columbia River Power System. The DSIs, until the last four years, have always been a substantial part of BPA's loads and revenues. For example, in 1942, the DSIs accounted for 92% of BPA's power commitments[7]. Based on more than $7.5 billion in Treasury amortization repayments since 1940, one can conservatively estimate that the DSIs have paid BPA amortization of approximately$2.5 billion or more (since DSI rates have historically exceeded preference customer rates, and during the 1980s, were substantially higher in order to pay for the residential exchange mandated by the Northwest Power Act).

To say that providing power to Intalco results in a "subsidy" (as some BPA customers have suggested) ignores the substantial equity in the BPA system that Alcoa and the other DSIs have contributed over the years. Alcoa was one of BPA's first customers, has consistently paid its bills, and like other valuable BPA customers, has an equitable claim to BPA power service. It is also clear that the DSI load reductions have permitted the region to meet growing public agency loads. The load reductions have also allowed regional utilities, including BPA, to make very lucrative sales outside the region. The preference customers now seem to assert a claim to virtually all of the benefit of BPA's surplus sales for themselves, a claim clearly at odds with the Regional Preference Act (16 U.S.C. § 837), the Northwest Power Act (16 U.S.C. §839f(c), and the Excess Federal Power provision (16 U.S.C. § 832m).

Benefits to BPA and Its Other Customers From the 7-year Agreement

a. Waiver of Rights to Surplus BPA Power

Following the Court's opinion in *Pacific Northwest Generating Cooperative v. BPA*, (9th Cir. Case No. 09-70228, August 28, 2009) (*PNGC II*), BPA approached Alcoa to discuss proposed modifications to the 7-year contract, from the version proposed in BPA's notice, to address elements of the Court's opinion. Provided that other terms of the contract remain as in the draft Agreement, Alcoa agreed to surrender any claim to additional power required to serve its loads. In *PNGC II,* the Court stated:

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[6] Bonneville Power Administration, *Columbia River Power For The People*, p. 123 (1981).
[7] *Id.*

> We can envision several situations in which BPA might reasonably conclude that a below-market rate sale to the DSIs is a sound business decision. First, as the court alluded to in *PNGC*, BPA's governing statutes likely require it to offer power within the Pacific Northwest at established rates before
>
> the agency may sell power outside the region. *See PNGC*, 550 F.3d at 876 n.35. If so, BPA might reasonably enter into a contract with the DSIs at the IP rate so as to "free up power to sell outside the Pacific Northwest." *Id.*

Slip. Op. at 11973.

In response, Alcoa agreed to revise the proposed 7-year Agreement to provide as follows:

> Other than as set forth in sections 4, 5, 6, and 23 of this Agreement, during the period October 1, 2009 through September 30, 2016, Alcoa will make no additional request for power from BPA, surplus or otherwise; *provided, further*, that Alcoa agrees not to file a petition for review in the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) challenging (a) any proposed or actual sale of surplus power by BPA to any other BPA customer, whether inside or outside the Pacific Northwest region, or (b) any rate adopted by BPA, and approved on a final basis by the Federal Energy Regulatory Commission, for the sale of surplus power; *provided, however,* that the foregoing commitment by Alcoa will be of no force or effect in the event the Ninth Circuit issues its mandate in a case in which it has granted a petition for review challenging this Agreement and has issued an order or opinion that declares or renders this Agreement void or if BPA terminates this Agreement.

This provision clearly frees up the power associated with one-third of the Intalco load (160 a MW), as well as an additional 150 MW of load that BPA has historically provided for the operation of Alcoa's Wenatchee smelter. These are both loads that will not be served under the 7-year Agreement for sales outside the Pacific Northwest, but which would otherwise be subject to regional preference. With this provision, Alcoa will not make any claims for the portion of its load that is unserved at the IP Rate in way that could interrupt BPA's sales outside the region. Alcoa believes such a claim would otherwise be meritorious and successful. *See Pacific Northwest Generating Coop. v. BPA*, 550 F.3d 846, 873 (9th Cir. 2008), *amended on denial of reh'g*, No. 05-75638, --F.3d--, 2009 WL 2386294 (9th Cir. Aug. 5, 2009), [8] Therefore, the waiver of Intalco's

[8] **"**We conclude that BPA's interpretation of its governing statutes as providing authority to sell surplus power to the DSIs under § 839c(f) at an FPS rate without first offering to sell that amount of power under either § 839c(d) or § 839c(f) at a rate set under § 839e(c) is not reasonable. The statutory text of the NWPA, the agency's own prior interpretation of the Act, and the NWPA's legislative history, are all to the contrary. We therefore hold

claim for its otherwise unmet power needs, that BPA must first offer within the Northwest region to Alcoa at the IP rate, has a significant economic value (measured by BPA's surplus power times the difference between market prices and the IP rate). It also has the value of not disrupting BPA's marketing of electric power sales outside the region at BPA's market-based rates, the benefits of which overwhelmingly accrue to BPA's preference customers.

b. Waiver of Lookback Claims

In further response to the Court's opinion in *PNGC II* Alcoa agreed (subject to other terms of the draft Agreement remaining in place) to waive its claim to the net difference it paid for power under the Block Sale Agreement and the IP rate in circumstances where BPA determines that (in its view) the damages waiver contained in the Block Sale Agreement is effective. Alcoa has quantified the basis for its claim and estimates that, by the end of the Block Sale Agreement, its damages reflected in that claim will be $195 million. Alcoa has included as Attachment A to this letter the Exhibit that it filed with the Ninth Circuit documenting its claim. The proposed revision to the contract provides:

> In the event BPA issues a final record of decision with respect to the issues remanded to BPA (the Remand ROD) by the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) in *Pacific Northwest Generating Cooperative, et al. v. Bonneville Power Administration*, 550 F.3d 846 (9th Cir. 2008) (*PNGC I*), and *Pacific Northwest Generating Cooperative, et al. v. Bonneville Power Administration*, Nos. 09-70228, 09-70236, 09-70988 (9th Cir. Aug. 28, 2009) (*PNGC II*), in which BPA determines that no payments are owing by Alcoa to BPA or by BPA to Alcoa, then Alcoa agrees that it waives any legal, equitable, or other claim or right of any nature that it has, or may have in the future, for money or any other remedy, with respect to the Block Power Sales Agreement by and between Alcoa, BPA, and Public Utility District No. 1 of Whatcom County, Washington (Contract No. 06PB-11744) (the Block Contract), as amended; *provided, however*, that the foregoing waiver by Alcoa will be of no force or effect in the event that the Ninth Circuit issues its mandate in a case in which it has granted a petition for review challenging the Remand ROD and has issued an order or opinion that finds such payments are required under the Block Contract or if BPA terminates this Agreement.

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that BPA improperly refused to offer the aluminum DSIs energy at a rate set under § 839e(c) before selling them power at an FPS rate."

BPA sought, and was denied rehearing on this question. Therefore, the surrender of Intalco's claim for one-third of its otherwise unmet power needs that BPA must first offer within the Northwest region to Alcoa at the IP rate has a significant economic value, as well as the value of not disrupting BPA's market-based electric power sales outside the region.

This waiver of the right to seek $195 million in restitution of the difference between the IP rate and the net power costs that Intalco actually incurred under the Block Power Sales Agreement forms additional consideration to BPA for entering into the 7-year contract. The Ninth Circuit in *PNGC II* observed:

> Petitioners also maintain that BPA's decision to enter into the amended contract was not consistent with sound business principles because the agency did not first seek a refund of funds it improperly paid to Alcoa pursuant to the 2007 Contract. As BPA notes, however, there is a significant possibility that the DSIs do not owe BPA a refund. *See infra* Part IV.

PNGC II, Slip op. at 11986-87, footnote 11. Alcoa imparts value to BPA in waiving its claim for damages (assuming that BPA concludes that neither party owes the other in the lookback) because Alcoa could otherwise pursue its damages either as an appeal of BPA's determination on the lookback or as a claim in the U.S. Court of Federal Claims. At the very least, elimination of the claim (as conditioned) will prevent BPA from having to mount a defense of the claim, with the attendant costs and risk (to BPA's other customers) associated with such litigation.

<u>Power reserves</u>

In its last rate case, BPA developed a standard for the reserves that the Northwest Power Act requires BPA to seek from its DSI customers. Alcoa also provides regional transmission reserves through its transmission contract with BPA. The proposed 7-year Agreement also contemplates the negotiation by BPA and Alcoa of additional valuable reserves to help BPA integrate wind-power and other renewable energy sources into its system:

> The Parties recognize that with the addition of certain electronic controls at the Intalco Plant, the Intalco Load can be varied to help accommodate within-hour fluctuations on BPA's system associated with wind power generation. The Parties agree to undertake discussions within 60 days after the execution of this Agreement to identify and implement any agreed to actions and agreements necessary to achieve such wind integration benefits.

Proposed Power Sale Agreement at Exhibit F, Section 2.

For the foregoing reasons, Alcoa believes that its historic contributions to the Pacific Northwest power system and the benefits that it can continue to contribute to BPA, its other customers, and the regional economy in the future, justify offering Alcoa physical power for service to its Intalco plant. Alcoa urges BPA to move forward with an Agreement that adheres to the proposal embodied in Draft Agreement, with the additional regional benefits that BPA would derive from Alcoa's modifications to the Agreement since the August 19, 2009 draft. This would allow equitable service to one of BPA's longest-term customers (Alcoa) and preserve over 2,000 jobs that are so important to the Northwest, particularly during this deep and protracted recession.

Alcoa, and the Ferndale, Washington, community, that has over 2,000 jobs associated with the Intalco facility, are grateful to BPA for seeking a middle ground that will give Intalco an opportunity to continue to operate under difficult market conditions. The benefits identified in this letter can only be achieved through physical power service from BPA. With an appropriate Agreement, Alcoa is willing to do its part to preserve industrial manufacturing capability that is so vital to regional employment, while also maintaining the balance-of-trade and security interests of the country.

Sincerely,

Mike F. Rousseau
Plant Manger, Alcoa Intalco Works

cc: Governor Gregoire,
NW Congressional Delegation

Pacific Northwest Generating Cooperative v. BPA

Case No.: 09-70228, 09-70236

Opening Brief of Intervenor Alcoa, Inc.

Exhibit 1:

Affidavit of Jack A. Speer
In Support of Opening Brief of Intervenor Alcoa, Inc. (Apr. 20, 2009)

Case No.: 09-70228, 09-70236

UNITED STATES COURT OF APPEALS
FOR THE NINTH CIRCUIT

PACIFIC NORTHWEST GENERATING COOPERATIVE, *et al.*,
Petitioners,

ALCOA INC., Intervenor,

v.

BONNEVILLE POWER ADMINISTRATION; et al., Respondents

AFFIDAVIT OF JACK A. SPEER

IN SUPPORT OF

OPENING BRIEF OF INTERVENOR ALCOA INC.

Michael C. Dotten
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Lake Oswego, OR 97035
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E-Mail: mcdotten@msn.com

STATE OF WASHINGTON)
) ss
Chelan County)

I, Jack A. Speer, attest as follows:

1) My name is Jack A. Speer. I am the owner of Speer Energy Consulting LLC, and serve as consultant to Alcoa Inc. ("Alcoa") in rate and contract proceedings before the Bonneville Power Administration ("BPA"). I am competent to testify on the matters contained herein, which are based on my personal knowledge.

2) In June 2006, Alcoa entered into the Block Power Sales Agreement with BPA. The Block Power Sales Agreement is contained in the Administrative Record in this proceeding. *See* A.R. 0216-0264.

3) As part of its obligations under the Block Power Sales Agreement, Alcoa is required to provide BPA with "contracts, invoices, or other documents reasonably necessary for BPA to verify the purchase price of power" used to calculate the monetary benefit provisions with respect to Alcoa's Intalco plant in Ferndale, Washington. E.R. 7, A.R. 0227.

4) The specific power sale contracts that Alcoa entered into are confidential documents containing commercially sensitive information.

5) The data that Alcoa supplied to BPA was marked as confidential.

6) Under the terms of the Block Power Sales Agreement, "Information provided to BPA which is subject to a privilege or confidentiality or nondisclosure shall be clearly marked as such and BPA shall not disclose such information without obtaining the consent of the person or Party asserting the privilege, consistent with BPA's obligations under the Freedom

of Information Act. BPA may use such information as necessary to provide service or timely bill for service under this Agreement. BPA shall only disclose information received under this provision to BPA employees who need the information for purposes of this Agreement." Block Power Sales Agreement Section 14(c), E.R. 11-12; A.R. 0239-0240.

7) Since 2006, Alcoa has provided BPA with such "contracts, invoices, or other documents" in accordance with the Block Power Sales Agreement. These documents evince the prices Alcoa actually paid for power under the individual power sale agreements in reliance on the agreement.

8) In an effort to cure the defects in the Block Power Sales Agreement identified in this Court's December 2008 decision in *Pacific Northwest Generating Cooperative v. Bonneville Power Admin.*, 550 F.3d 846 (Dec. 18, 2009), BPA offered Alcoa a contract amendment (the "Amendment") in January 2009 (the "Amended Contract"). A copy of the Amendment is included in the Administrative Record before this Court. *See* E.R. 13-35; A.R. 0267-0287.

9) The Amendment, which is the subject of this proceeding, established the Monetary Benefit BPA will use to attempt to address the net difference between BPA's statutory industrial power ("IP") rate and the market rate at which BPA would have had to acquire power to serve Alcoa. The fifth recital of the Amendment recognizes the significantly higher rates Alcoa actually paid for power between December 2008 and September 2009 by stating, "In reliance on the payments to be made to it by BPA under the Agreement, Alcoa acquired power in the wholesale power market to serve its industrial load during the full term of the Agreement. The average cost of Alcoa's acquisitions exceed BPA's currently forecasted wholesale market

price for the Amendment Period". E.R. 15, A.R. 0267.

10) The Amendment recognizes that BPA had information before it on the rates Alcoa actually paid to purchase power from non-BPA sources in reliance on the underlying Contract. *See, e.g.*, E.R. 15, A.R. 0267. ("The average cost of Alcoa's acquisitions exceed BPA's currently forecasted wholesale market price for the Amendment Period." Such information, however, is not included in the Administrative Record before the Court in this proceeding, perhaps because of BPA's understanding of the confidentiality provisions of the Contract.

11) Attached to this affidavit, as Exhibit A, is a true and correct copy of rebuttal testimony I prepared on Alcoa's behalf in the WP-10 proceeding currently pending before BPA. That proceeding will determine, among other things, the IP rate applicable to Alcoa and other direct service industrial ("DSI") customers for Fiscal Year ("FY") 2010-2011. *See* 74 Fed. Reg. 6,609 (Feb. 10, 2009).

12) The rebuttal testimony accurately summarizes information submitted by Alcoa to BPA under the Block Power Sales Agreement, namely, the rates it actually paid to purchase power from non-BPA sources in reliance on that agreement, by aggregating the data and not identifying the specific power suppliers or the prices under the individual power sale agreements. Despite the fact that it had the specific information on the Alcoa power sale agreements and considered it as part of the decision at issue in this proceeding, BPA did not include the information as part of the Administrative Record here.

13) The rebuttal testimony includes two exhibits that relate to issues now before the Court – Rebuttal Exhibits 3 and 6. Alcoa initially submitted these exhibits on March 20, 2009, as part of my original direct testimony in

the WP-10 proceeding.

14) On April 12, 2009, the BPA-10 Hearing Officer in WP-10 granted Pacific Northwest Generating Cooperative's ("PNGC") and BPA's Motions to Strike portions of my original testimony. A copy of the Hearing Officer's Order is attached as Exhibit B to this affidavit.

15) On April 17, 2009, Alcoa submitted my rebuttal testimony, which included Rebuttal Exhibit 3 and Rebuttal Exhibit 6. Those exhibits were identical to exhibits attached to my original testimony, but which the Hearing Officer struck based on the motions to strike. The Hearing Officer's Order, however, suggested that Alcoa could submit the exhibits as rebuttal testimony in order to respond to the testimony of PNGC and other preference customers relating to the allegations that power provided to Alcoa constituted a subsidy. PNGC has attempted to prevent evidence of Alcoa's actual net power costs in BPA proceedings. Alcoa believes that such evidence is responsive to PNGC's continuing allegations that the net price Alcoa pays for power is in violation of BPA's statutes and a "subsidy."

16) Rebuttal Exhibit 3 summarizes the rates Alcoa actually paid for power for the Intalco plant from non-BPA sources between December 2008 and September 2009 – the term of the Amendment at issue here.

17) The figures and calculations in Rebuttal Exhibit 3 are based on, and accurately reflect, the information Alcoa submitted to BPA as part of its obligations under the Block Power Sales Agreement, namely "contracts, invoices, and other documents." The figures and calculations accurately reflect the price Alcoa has paid to provide the Intalco plant with power between December 2008 and September 2009. The figures also include estimates of revenues from future sales of surplus power since the Intalco plant expects to use less power than purchased during this period. As

summarized in Rebuttal Exhibit 3, Alcoa's average price for power from non-BPA sources between December 2008 and September 2009 (after remarketing unused power) is expected to be $ $62.13 per megawatt hour ("MWh").

18) During that same time period, the Monetary Benefit under the Amendment will average $15.24 per MWh.

19) The net price expected to be paid by Alcoa during the term of the Contract Amendment (rates paid, less remarketing revenue and less Monetary Benefit) is $46.89 per MWh.

20) The actual price expected to be paid by Alcoa ($46.89) exceeds the published average industrial power ("IP") rate ($33.76) by $13.13 per MWh. As a result, Alcoa is expected to pay $27,768,590 in excess of the IP rate for power during the term of the Amendment.

21) Rebuttal Exhibit 6 aggregates Alcoa's anticipated overpayments for power in excess of the IP rate during the entire term of the Block Power Sales Agreement (October 2006 through September 2011). The figures and calculations in Rebuttal Exhibit 6 are based on, and accurately reflect, the information Alcoa submitted to BPA as part of its obligations under the Block Power Sales Agreement, namely "contracts, invoices, and other documents."

22) Rebuttal Exhibit 6 specifically aggregates the following categories of overpayments: (a) Alcoa's overpayments between October 2006 and November 2008 ($20,719,823); (b) Alcoa's expected overpayments between December 2008 and September 2009 ($27,768,590); (c) Alcoa's expected overpayments between October 2009 and September 2011 ($98,175,231); and (d) overpayments due to BPA's incorrect calculation of the IP-07 rate ($48,648,685). In total, Alcoa is expected to pay $195,312,329 for power

during the term of the Block Power Sales Agreement (October 2006 through September 2011) that it would have had BPA provided Alcoa with physical power at a correctly calculated IP rate.

23) On April 9, 2009 BPA held a "DSI Service Workshop" various issues relating to continuing DSI service under the terms of the opinion in *PNGC*. I submitted, and BPA accepted for the record, the exhibits which I had attempted to introduce as direct testimony in the WP-10 proceeding. Those exhibits are identical to the exhibits attached to this affidavit with the exception that Column P of Rebuttal Exhibit 3 (IP Rate $/MWh) contained an error in the last line of the exhibit that did not impact any of the calculations in the exhibit. That error has been corrected in my rebuttal testimony exhibit and in the exhibit attached to this affidavit. I have also resubmitted the corrected exhibit as part of the DSI Service Workshop record.

Executed this 20th day of April 2009.

Jack A. Speer

Jack A. Speer
Speer Energy Consulting LLP
918 Briarwood Dr.
East Wenatchee, WA 98802

Subscribed and sworn to before me, this 20th day of April 2009.

TARA RENEE PIRES
COMMISSION EXPIRES
NOTARY
PUBLIC
AUG. 06, 2012
STATE OF WASHINGTON

Tara Renee Pires

NOTARY PUBLIC FOR THE STATE OF WASHINGTON

My commission expires: August 06, 2012.

Pacific Northwest Generating Cooperative v. BPA

Case No.: 09-70228, 09-70236

Affidavit of Jack A. Speer

Exhibit A:

Rebuttal Testimony of Jack A. Speer
(WP-10-E-AL-02, Apr. 17, 2009) and (WP-10-E-AL-02-E01, Apr. 20, 2009)

UNITED STATES OF AMERICA

US DEPARTMENT OF ENERGY

BEFORE THE

BONNEVILLE POWER ADMINISTRATION

2010 WHOLESALE POWER RATE ADJUSTMENT PROCEEDING	)) BPA Docket WP-10

REBUTTAL TESTIMONY OF JACK A. SPEER

ON BEHALF OF

ALCOA INC

FILED: APRIL 17, 2009

Q. Please state you name and your affiliation.

A. My name is Jack A. Speer. I am the owner of Speer Energy Consulting LLC, and represent Alcoa Inc. in this proceeding. My qualifications are contained in WP-10-Q-AL-E01.

Q. Did you file direct testimony in this proceeding?

A. Yes. I filed direct testimony marked as WP-10-E-AL-01.

Q. What is the purpose of this rebuttal testimony?

A. I am providing rebuttal testimony in response to the direct testimony of the JP7 group (PPC, ICNU, and Tacoma Power), PNGC, and the Western Public Agency Group (WPAG).

<u>**Typical Margins**</u>

Q. Did parties file testimony in this case recommending that BPA increase its "typical margins" charged as part of the IP rate?

A. Yes. Both PNGC and the JP-7 Group propose that BPA adjust upward the typical industrial margin required by Section 7(c) of the Northwest Power Act. WP-10-E-PN-01, p. 5, line 8 through p. 7, line 10 and WP-10-E-JP7-1, p. 6, line 9 through p. 7, line 13. The testimony is based entirely on supposition that such margins have changed because "many utility costs have risen during that time [since the last study 4 years ago]." WP-10-E-JP7-1 at 5, lines 15-17. PNGC testifies that: (1) retail sales are falling, so margins must be increasing; and (2) "one could conclude" that typical industrial margins have also changed because the Handy-Whitman Index of Public Utility Construction Costs has risen. WP-10-E-PN-01, p. 6, line 4 through p. 7- line 10.

Q. Do these conclusions make sense?

A. No. First, as the JP7 Group notes, in the past the PPC has conducted surveys of its members to provide data from which BPA could calculate a typical margin. It didn't do so this year, although presumably it could have done so in order to support its testimony. The typical industrial margin has been constant for many rate cases even when the PPC data was available. So the passage of time and inflation in utility rates should not lead to the inference that typical margins have increased. When data was available, typical margins didn't increase so, all the more, in the absence of any hard evidence on this point, no inference is justified that such typical margins have increased.

Second, a reduction in retail sales doesn't necessarily lead to an increase in margins. Typical, cost-based ratemaking implies that a customer pays the cost that a utility incurs in serving a customer or customer class. As retail sales decrease, so do the costs of serving that load. In addition, sound utility practice would be to reduce expenses as much as possible, before increasing ratepayer margins to all classes. That may also have happened. It is just as likely to infer that the costs of providing service to customers have decreased in proportion to retail sales as to infer that margins have increased. And even if there were evidence that margins to other customers were increasing (rather than just inferred) that does not constitute evidence that *industrial* margins are increasing. Many of the industrial contracts may have margins that are fixed under long-term contracts. Moreover, as I understand it in developing the typical margin BPA must consider "the comparative size and character of the loads served, the relative costs of electric capacity, energy, transmission and related delivery facilities provided and direct and indirect overhead costs" as related to delivery of power to industrial customers. In other words, PNGC, and the JP7 parties ask the

Administrator to ignore the characteristics he is required to consider and to presume there has been an increase in typical industrial margins based on the further assumption that increases in costs, in general, have increased typical industrial margins.

Finally, the Handy Whitman Index of Public Utility Construction Costs, by its own name, suggests that it has almost nothing to do with utility margins—certainly no direct correlation could be drawn sufficient to support the statutory standards that BPA must consider as outlined above.

Q. **Could the parties recommending an increase in industrial margin have submitted data to support their testimony on this point?**

A. Yes. As indicated, the PPC has conducted these surveys in the past for BPA and thus could gather such data. Presumably, no party would have better access to customers who are paying these margins than the Industrial Customers of Northwest Utilities (ICNU), many of whose members are among the larger industrial customers of publicly owned utilities in the region. Yet ICNU's witness not only failed to produce any data indicating that typical industrial margins have increased as part of his testimony, ICNU refused to provide any data whosoever in response to Alcoa's data request asking for evidence of the asserted increases in typical margins. *See* Alcoa Data Request AL-JP7-3 and response (attached as Rebuttal Exhibit 1).

Q. **The Joint Parties recommend including the Washington State revenue tax in the typical industrial margin. WP10-E-JP7-1, p. 6, lines 1-8. Do you agree with this recommendation?**

A. No. The Washington State revenue tax is not a "typical margin included by such public body and cooperative customers in their retail industrial rates." Instead, it is a tax imposed by the State of Washington, unrelated to the margin the utilities charge (and keep) for their own use. It therefore doesn't fit within definition of margin within the Northwest Power Act or as understood by BPA in the past.

DSI Load Assumptions

Q. **The JP7 parties testified as follows:**

> Our understanding is that BPA determined the number by calculating the difference between the IP rate and market power price and then calculating the MWHs that could be provided at a cost of $59 million, which represents the cost that the agency deems appropriate to incur for the DSIs
>
> *Q. Is this a proper method of forecasting DSI load?*
>
> A. No. BPA should forecast DSI loads using normal load forecasting methods aimed at accurately estimating actual amounts of expected load.
>
> *Q. Why is it improper to simply assume that the DSIs will operate at a sufficient level to impose the entire cost BPA appears willing to incur for the DSIs?*
>
> A. There are several reasons. The first is that the economy has deteriorated markedly over the past several months. Commodity prices have taken a hit. A recent Wall Street Journal table (3/12/09) shows that the spot market price for aluminum is down over 50% from a year ago. Press reports of statements from Alcoa and CFAC indicate that they could shut down or curtail production. BPA has not provided a reasonable basis for its assumptions about the likely magnitude of DSI load.
>
> *Q. Would it ever be appropriate for BPA to assume a limit on the amount of costs it assumes to occur to provide DSI service?*
>
> A. Yes. Our understanding is that BPA has no obligation to serve the DSIs, so if it chooses to, and is authorized to do so, it could make a reasonable determination to serve them only up to an amount that would correspond with a certain cost. However, the issue here is that BPA is unreasonably assuming that the DSIs will operate at a level that will correspond with the amount of service that BPA may provide. WP-10-E-JP7 1, p. 2, line 7 through p. 3, line 9.

Do you agree with the JP7 parties' testimony?

A. I disagree with the JP7 parties' conclusion about the likely level of DSI operations if DSIs receive the IP Variable Rate I propose. I agree that BPA starts with the assumption that the level of service should be derived based on an assessment of what BPA believes its customers can "afford" or "is appropriate to incur for the DSIs." The $59 million figure that the JP7 parties mention is the same dollar level for the Monetary Benefits proposal that the Court found to be invalid. BPA uses that figure to back into an amount of power it will provide, as opposed to a determination of the amount of power it determines it has available to serve the DSI load [see WP-10-E-BPA-10, page 11, lines 17-21 and page 12, lines 19-25]. BPA does this by taking the $59 million and dividing by the difference between the market rate and the IP rate to arrive at the number of average megawatts BPA will sell to the aluminum DSIs. The JP7 parties and Alcoa agree that this is improper. However, unlike the JP7 parties, I believe BPA's approach simultaneously: a) results in too little power for Alcoa's Intalco smelter to operate (as opposed to too much power as JP7 parties testify) and b) derives from an artificial dollar cap that was successfully challenged by both Alcoa and PNGC in the *PNGC* case. Alcoa believes that BPA has ample authority: (1) to provide physical power service to Alcoa; (2) to price this service at an IP rate that is developed consistent with the methodology that BPA used in developing its final IP rate in its WP-07 Supplemental rates; (3) to develop a variable rate that will recover BPA's allocated IP costs over the long-term of the contract that BPA is to develop; and (4) to provide reserve credits to the DSIs consistent with the methodology and valuation methods proposed in this testimony. Alcoa does not believe that BPA should begin its service assumptions with a dollar limit as suggested by the JP7 parties.

Q. Do you agree with the JP7 parties in how BPA should exercise its discretion to serve DSI loads?

A. No. Given the discretion to sell DSIs firm power, or not, BPA should serve these historic DSI loads. To fail to do so would result in the death of an industry with flat loads that has been historically served by BPA while BPA serves the JP7 group's growing loads at rates that do not reflect the cost of providing their growing service needs.

Appropriate Pricing Principles

Q. Do you agree with PNGC's argument that the DSIs "embedded cost of service" is $215 million and that a lower rate is a subsidy to the DSIs?

A. No. The rate directives in section 7 of the Northwest Power Act require an IP rate that is based on the PF rate with certain adjustments. It would not be appropriate to use a different methodology that contradicts the plain language of the law in order to allocate additional costs to the IP rate as suggested by PNGC. If the DSIs are charged market-based rates, rather than the properly constructed IP rates, then a clear subsidy would result in favor of PNGC and the other preference customers. BPA's rates to the DSIs are statutorily constrained in a way that simply does not permit marginal cost pricing. So the load growth of the preference customers has not been reflected in BPA's past rates, and won't be for this rate period. BPA, however, would voluntarily send the wrong price signals to the growing preference customer loads if it artificially increases the DSI rate in order to lower rates for preference customers at the cost of the demise of the entire DSI customer class.

Q. Is there another reason for serving the historic DSI loads at accurately measured embedded cost?

A. Yes. For nearly 70 years, the DSIs have paid rates that have paid off the debt for large portions of BPA's system. While they have not built up "equity" in the sense of gaining ownership of BPA's system, they certainly have contributed to the construction of the Federal Columbia River Power System and the related transmission that give rise to BPA's ability to serve consumer owned utility customers at the low rates they enjoy today.

Existence of a Contract

Q. **WPAG testifies as follows:**

> *Q. "Does BPA have in place a contract with the smelter DSIs for a power sale during the rate period?*
>
> A. Not to our knowledge. The contracts offered to the smelter DSIs were not executed, so there is currently no contract with them for a power sale for the coming rate period." WP-10-E-WG-01, p. 20, lines 1-5.

Do you agree with WPAG's conclusion?

A. No. As I understand the Ninth Circuit opinion to which the WPAG witness refers, the form of the monetary benefit in the DSI Block Sale Agreements was invalidated, but the Court did not hold that the contracts were void, as if they never existed. Instead, the Court observed that BPA does have the authority to sell physical power to the DSIs and remanded the contract back to BPA to make a determination as to the impact of the contract's severability clause on the other ongoing provisions of the contract. The Block Sale Agreement has a provision for the sale of physical power to Alcoa (and CFAC) and it is possible that BPA will conclude that portion of the contract may be performed for its intended term—that is, through September 2011.

The Question of Subsidy

Q. **WPAG testifies as follows concerning service to the DSIs:**

> Unfortunately, there is no assurance that the cost to preference customers of subsidizing the power costs of these DSIs will be limited to the $59 million forecast in the Initial Proposal, or at or near zero based on more recent power market prices.
>
> The market price of power changes on a daily basis. While the current forward prices might suggest a near zero-cost to

> preference customers from a power sale to the DSIs (forecast IP revenues and market power costs being nearly equal), if market power prices go up during the rate period, the cost to preference customers of this subsidy could escalate. We have seen recent examples of this phenomenon. In the initial rate proposal for the 2000 BPA rate case, power sales commitments by BPA exceeded its supply, and it was generally assumed that market power could be procured at a price that would not cost materially more than the PF rate, resulting in no major cost impacts to preference customers from such power sales commitments. Unfortunately, the market price of power escalated substantially, resulting in major changes to the costs of these commitments. WP-10-E-WG-01, p. 20, lines 17-22 and p. 21, lines 3-13.

Do you agree with WPAG's assertions?

A. No. Alcoa does not agree that the payment by BPA for power to serve the DSIs is a subsidy. This question has been presented to the courts on several occasions, only the most recent being in the case WPAG refers to in its testimony. As I understand it, the Ninth Circuit has concluded that BPA has discretion to purchase power for the DSIs and that it may roll the cost of such purchases into its rates, including preference customer rates and that BPA should charge the IP rate for sales of power to the DSIs. The WPAG testimony labels this result as a "subsidy" and concludes:

> Finally, it is neither fair nor practical to ask preference customers to subsidize jobs outside their service territories while jobs are being lost within their service territories. Therefore, we recommend BPA assume zero cost to serve DSIs for purposes of setting rates in this rate period. WP-10-E-WG-01, p. 21, lines 18-22 through p. 22, lines 1-2.

Q. Would that be a prudent assumption on BPA's part?

A. No. BPA has announced that it will undertake a "lookback" proceeding in the near future to determine whether rates to the DSIs should be adjusted due to the Ninth Circuit's invalidation of the former Monetary Benefit. In that proceeding, Alcoa will demonstrate that the Monetary Benefit caused it to pay, and will, in the future cause it to pay rates that exceed the IP rate that the Ninth Circuit held BPA must collect for DSI service.

Q. **PNGC asserts in WP-10-E-PN-01 that BPA's prior IP ratemaking is flawed through the use of "nominal loads." WP-10-E-PN-01, p. 8, line 24 through p. 10, line 2. Does Alcoa agree?**

A. We agree that the monetization of the DSI contracts led to odd IP ratemaking, but contrary to PNGC's allegations of subsidy resulting from the existing rates, we think that BPA's "lookback" proceeding should reach just the opposite conclusion about BPA's prior rates, particularly because they exceeded the adopted IP rates.

Q. **Please describe the amount that Alcoa has paid or is likely to pay above the IP rate because of the monetized contract?**

A. The expected overpayment can be segregated into 4 categories:

1. First, is the difference between the amounts actually paid for power from non-BPA sources minus the amount of BPA monetized benefits received compared to the IP-07 and IP-07R rates from October 1, 2006 through November 30, 2008 under the original DSI Block Sale Agreement. This is summarized in Rebuttal Exhibit 2 to this testimony.

2. Second, is the difference between what Alcoa is likely to pay for power pre-purchased from non-BPA sources minus the monetized benefits BPA paid to Alcoa under the Amended Block Sale Agreement and minus revenues received from the remarketing of surplus pre-purchased power compared to what Alcoa would have been paid under the IP-07R rate from December 1, 2008 through September 30, 2009. This is summarized in Rebuttal Exhibit 3 to this testimony.

3. Third is the difference between what Alcoa is likely to pay for power from BPA at an expected IP rate plus what Alcoa is likely to pay for pre-purchased power from non-BPA sources minus any BPA monetary benefits BPA pays Alcoa during such period

and minus revenues from remarketing pre-purchased power as compared to what Alcoa would have paid to BPA under the proposed IP-10 rate from October 1, 2009 through September 30, 2011. This is summarized in Rebuttal Exhibit 4 to this testimony.

4. Fourth is the difference between the improperly high IP-07 rate and what Alcoa would have paid had BPA under the revised the IP-07 rate during the WP-07R proceeding. When BPA conducted its supplemental 2007 rate case, it adjusted future PF rates to comply with the remanded Residential Exchange Program settlement agreements. This had the effect of reducing the IP rate as well. However, BPA did not adjust the incorrect IP-07 rate methodology retroactively to be consistent with the correct methodology used to determine the IP-07R rate. This resulted in artificially high IP-07 rate as compared to the IP-07R rate. This is summarized in Rebuttal Exhibit 5 to this testimony.

Q. **Did Alcoa object to the IP-07 methodology?**

A. No. Alcoa was not purchasing power under that rate, but under the monetized power contract at the time, and was not impacted by that rate. However, Alcoa did actively advocate for a correctly calculated IP rate in the WP-07 Supplemental proceeding in the (correct) belief that the Ninth Circuit might invalidate the Monetary Benefit in the Block Sale Agreement and mandate the application of a correctly calculated IP rate.

Q. **What should the IP-07 rate have been?**

A. It is very difficult to replicate the calculations in the development of the IP-07 rates under the methodology used in the IP-07R rate development. As an estimate I assume that the IP-07 rates would have been equal to the IP-07R rates because the DSI loads remained roughly the same in both rate periods under the Block Sale Agreement.

Q. **Please summarize the total amount of the expected overpayment between October 1, 2006 and September 30, 2011.**

A. Contrary to WPAG's assertion of a "subsidy" the total expected overpayment by Alcoa in excess of the appropriate IP rate is summarized in Rebuttal Exhibit 6.

Q. How do you propose that BPA remedy the expected overpayment summarized in Rebuttal Exhibit 6?

A. As described on page 16, lines 15 through page 17, line 6 of WP-10-E-AL-01, we propose a true-up mechanism to insure that aluminum variable rate DSI customers will not pay less than the standard IP rate for contracted power. We believe the overpayment amount should be a part of that true-up mechanism.

Q. Do you propose that the entire $195 million shown in Rebuttal Exhibit 6 be included in the variable rate true-up calculation?

A. No. We realize the amount of work required for BPA to retroactively revise its rates from October 1, 2006 through September 30, 2008. In the spirit of cooperation and long-term problem solving we propose to eliminate any adjustment in the fourth category identified in Rebuttal Exhibit 6 (Overpayments Due to Improper IP-07 Rate) in the true-up of a variable aluminum rate. This would reduce the total estimated true-up to the $147 million subtotal for the first three categories shown in Rebuttal Exhibit 6. If the variable rate is not adopted, Alcoa of course reserves the right to claim the total amount as damages in the appropriate forum.

Q. How will the true-up be calculated for the other aluminum company that may have a contract that allows purchases under the variable aluminum rate?

A. A true-up using the same methodology would be used beginning with power costs under BPA contracts on October 1, 2006. Of course, the numbers will be different for the other company because of different operating levels and different power costs.

Q. What would the effect be of adopting WPAG's recommendation as to assumptions about DSI service costs in this case?

A. BPA, in its "lookback proceeding," or the Court of Appeals or another court, could conclude during the two-year proposed term for these rates that BPA owes Alcoa the difference between its net power costs and the IP rate. The result of WPAG's "assume no cost or no service" recommendation could well result in a $195 million under-recovery of costs to BPA. The more reasonable way to resolve BPA's uncertainties would be for BPA to adopt the Variable Rate that Alcoa proposes in this rate case which would, as I testified, spread the impact of any restoration of overpayment by the DSIs over longer-term contracts that will negotiated in follow-on BPA proceedings.

Value of Reserves Adjustment

Q, Did parties testify on value of reserve adjustments in this proceeding?

A. Yes. But the testimony largely dealt with what should be contained in the contracts that will wrap around whatever value of reserve credits BPA adopts for this rate case. As I understand it, those issues are to be addressed in a parallel proceeding.

Q. Does this complete your testimony?

A. Yes

Response is past due after seven (7) days.

Request (click to view)	Exhibit	Responded	Requesting Party	Responding Party	Date Filed	Response (click to view)
AL-JP7-1	WP-10-E-JP7-01	Yes	ALCOA	Joint Party 7	3/26/2009 2:40 PM	Select Request to view Response
AL-JP7-2	WP-10-E-JP7-01	Yes	ALCOA	Joint Party 7	3/26/2009 2:42 PM	Select Request to view Response
AL-JP7-3	WP-10-E-JP7-01	Yes	ALCOA	Joint Party 7	3/26/2009 2:43 PM	Select Request to view Response

You are viewing page 1 of 1

Request Detail

Request ID: AL-JP7-3
Page Number: 6
Line Number: 1-21
Exhibit Filing: WP-10-E-JP7-01

Technical Contact Name: Michael Dotten
Technical Contact Phone: 503.882.4937
Technical Contact Email: mcdotten@msn.com
Legal Contact Name: Michael Dotten
Legal Contact Phone: 503.882.4937
Legal Contact Email: mcdotten@msn.com

Request Text:

Please provide all electric power bills issued to each of the Industrial Customers of Northwest Utilities' ("ICNU") members for all periods between January 1, 2007, and March 24, 2009, for facilities located in the Pacific Northwest.

Response Detail

Date Response Filed: 4/2/2009 3:44:31 PM
Contact Name: Irion A. Sanger
Contact Phone: 503.241.7242
Contact Email: ias@dvclaw.com
Response Text:

ICNU objects to the data request because the data request is vague and ambiguous, the data request is not relevant to the issues identified in this proceeding, the data request seeks information not addressed in the testimony, the production of the data requested would be unduly burdensome, the data request is overly broad, the production of the requested data could reveal highly confidential competitive information, and ICNU intervened for ICNU and did not request party status for its members. Notwithstanding these objections, ICNU responds that it has no documents responsive to this request.

Files Submitted for this Response:

REBUTTAL EXHIBIT 2

Overpayment Above IP Rate in Effect from October 1, 2006 through November 30, 2008

Notes: 1. IP rates are calculated at 100 % Load Factor
2. Loads are actual Intalco energy up to BPA contract limits

Year	Month	aMW	Hours	MWh	Rate Paid	Dollars Paid	BPA Ben. $/MWh	BPA Benefit $ Paid	Actual Dollars Net $ Paid	Actual Rate $/MWh	IP Rate $/MWh	IP Dollars $ at IP Rate	Overpayment $/MWh	Overpayment $
2006	Oct	192.4	745	143,301	$65.69	$9,413,033	18.32	$ 2,625,403	$6,787,630	$47.37	44.98	$ 6,445,679	$2.39	$341,951
	Nov	197.0	720	141,809	$50.59	$7,173,542	17.96	$ 2,547,246	$4,626,296	$32.62	52.03	$ 7,378,322	-$19.41	-$2,752,026
	Dec	200.2	744	148,961	$64.23	$9,567,658	17.62	$ 2,625,403	$6,942,255	$46.60	54.40	$ 8,103,478	-$7.80	-$1,161,223
2007	Jan	201.2	744	149,719	$61.01	$9,134,128	17.56	$ 2,628,403	$6,505,725	$43.45	49.08	$ 7,348,209	-$5.63	-$842,484
	Feb	242.7	672	163,102	$61.27	$9,992,685	14.54	$ 2,371,332	$7,621,353	$46.73	50.41	$ 8,221,972	-$3.68	-$600,619
	Mar	320.0	744	238,080	$59.82	$14,241,946	11.01	$ 2,622,403	$11,619,543	$48.81	48.06	$ 11,442,125	$0.75	$177,418
	Apr	320.0	719	230,080	$59.82	$13,763,386	11.08	$ 2,548,889	$11,214,497	$48.74	39.68	$ 9,129,574	$9.06	$2,084,922
	May	320.0	744	238,080	$59.82	$14,241,946	11.01	$ 2,620,330	$11,621,616	$48.81	34.82	$ 8,289,946	$13.99	$3,331,670
	Jun	320.0	720	230,400	$59.82	$13,782,528	11.06	$ 2,548,585	$11,233,943	$48.76	33.01	$ 7,605,504	$15.75	$3,628,439
	Jul	320.0	744	238,080	$59.82	$14,241,946	11.01	$ 2,620,434	$11,621,512	$48.81	40.61	$ 9,668,429	$8.20	$1,953,083
	Aug	320.0	744	238,080	$59.82	$14,241,946	11.06	$ 2,633,372	$11,608,574	$48.76	45.84	$ 10,913,587	$2.92	$694,986
	Sep	320.0	720	230,400	$59.82	$13,782,528	11.01	$ 2,535,743	$11,246,785	$48.81	48.22	$ 11,109,888	$0.59	$136,897
	Oct	358.0	745	266,705	$61.66	$16,445,005	12.03	$ 3,207,583	$13,237,422	$49.63	45.11	$ 12,031,063	$4.52	$1,206,359
	Nov	361.0	720	259,942	$61.12	$15,887,753	12.09	$ 3,142,273	$12,745,480	$49.03	52.03	$ 13,524,782	-$3.00	-$779,302
	Dec	358.8	744	266,938	$60.30	$16,095,854	12.03	$ 3,210,226	$12,885,628	$48.27	54.40	$ 14,521,427	-$6.13	-$1,635,799
2008	Jan	367.2	744	273,179	$60.75	$16,594,829	11.87	$ 3,242,807	$13,352,022	$48.88	49.08	$ 13,407,625	-$0.20	-$55,603
	Feb	367.4	696	255,735	$62.14	$15,891,382	12.20	$ 3,120,147	$12,771,235	$49.94	50.34	$ 12,873,700	-$0.40	-$102,465
	Mar	368.6	744	274,247	$61.01	$16,731,830	11.48	$ 3,149,518	$13,582,312	$49.53	47.94	$ 13,147,401	$1.59	$434,911
	Apr	369.4	719	265,617	$59.17	$15,717,535	12.22	$ 3,246,157	$12,471,378	$46.95	39.80	$ 10,571,557	$7.15	$1,899,821
	May	375.5	744	279,393	$58.03	$16,213,567	11.64	$ 3,251,633	$12,961,934	$46.39	34.82	$ 9,728,464	$11.57	$3,233,470
	Jun	384.2	720	276,636	$56.40	$15,601,771	11.39	$ 3,150,146	$12,451,625	$45.01	32.82	$ 9,079,194	$12.19	$3,372,431
	Jul	381.3	744	283,701	$60.93	$17,285,620	11.46	$ 3,251,633	$14,033,987	$49.47	40.76	$ 11,563,653	$8.71	$2,470,334
	Aug	379.5	744	282,336	$61.30	$17,306,910	11.52	$ 3,253,363	$14,053,547	$49.78	45.70	$ 12,902,755	$4.08	$1,150,792
	Sep	380.8	720	274,165	$59.39	$16,282,344	11.49	$ 3,150,146	$13,132,198	$47.90	48.34	$ 13,253,136	-$0.44	-$120,938
	Oct	381.1	745	283,947	$55.32	$15,708,287	11.45	$ 3,251,633	$12,456,654	$43.87	39.01	$ 11,076,772	$4.86	$1,379,882
	Nov	336.7	720	242,415	$59.77	$14,489,536	13.42	$ 3,253,363	$11,236,173	$46.35	41.10	$ 9,963,257	$5.25	$1,272,917
Total/Avg				6,175,048	$59.95	$ 369,829,493	$12.67	$75,808,171	$ 294,021,322	$47.28	$44.71	$273,301,499	$2.57	$20,719,823

REBUTTAL EXHIBIT 3 (Corrected 4-20-09)

Expected Overpayment Above IP Rate in Effect from December 1, 2008 through September 30, 2009

Notes:
1. IP rates are calculated at 100 % Load Factor
2. Loads are estimated
3. Market rates are estimated
4. Market rate forecast is as of March 16, 2009

Year	Month	Intalco Load aMW	Hours	Intalco Load MWh	Prepurchased MWh	Prepurchased $/MWh	Market Sales MWh	Market Rate $/MWh	Rate Paid	Dollars Paid	BPA Ben. $/MWh	BPA Benefit $ Paid	Actual Dollars Net $ Paid	Actual Rate $/MWh	IP Rate $/MWh	IP Dollars $ at IP Rate	Overpayment $/MWh	Overpayment $
2008	Dec	304.7	744	226,667	234,360	59.82	7,692.96	55.77	59.96	$13,590,379	$ 14.20	$3,218,672	$10,371,707	$45.76	42.96	$ 9,737,616	2.80	$634,091
2009	Jan	300.4	744	223,483	234,360	59.82	10,877.28	38.11	60.88	$13,604,882	$ 15.35	$3,430,460	$10,174,422	$45.53	36.51	$ 8,159,354	9.02	$2,015,068
	Feb	296.0	672	198,912	211,680	59.82	12,768.00	34.13	61.47	$12,226,926	$ 15.35	$3,053,299	$9,173,627	$46.12	37.54	$ 7,467,156	8.58	$1,706,470
	Mar	288.0	743	213,984	234,045	59.82	20,061.00	27.29	62.87	$13,453,107	$ 15.35	$3,284,654	$10,168,453	$47.52	34.96	$ 7,480,881	12.56	$2,687,572
	Apr	288.0	719	207,072	226,485	59.82	19,413.00	22.14	63.35	$13,118,529	$ 15.35	$3,178,555	$9,939,974	$48.00	32.45	$ 6,719,486	15.55	$3,220,487
	May	288.0	744	214,272	234,360	59.82	20,088.00	19.55	63.60	$13,626,695	$ 15.35	$3,289,075	$10,337,620	$48.25	26.70	$ 5,721,062	21.55	$4,616,557
	Jun	288.0	720	207,360	226,800	59.82	19,440.00	25.73	63.02	$13,066,985	$ 15.35	$3,182,976	$9,884,009	$47.67	22.62	$ 4,690,483	25.05	$5,193,526
	Jul	288.0	744	214,272	234,360	59.82	20,088.00	35.55	62.10	$13,305,287	$ 15.35	$3,289,075	$10,016,212	$46.75	30.17	$ 6,464,586	16.58	$3,551,625
	Aug	288.0	744	214,272	234,360	59.82	20,088.00	38.01	61.86	$13,255,870	$ 15.35	$3,289,075	$9,966,795	$46.51	35.91	$ 7,694,508	10.60	$2,272,288
	Sep	288.0	720	207,360	226,800	59.82	19,440.00	34.94	62.15	$12,887,942	$ 15.35	$3,182,976	$9,704,966	$46.80	37.78	$ 7,834,061	9.02	$1,870,906
Sum/Avg		291.7	729.4	226,667	234,360.00	59.82	169,956.24	33.12	62.1	$132,136,602	15.24	$32,398,818	$99,737,784	$ 46.89	33.76	$71,969,194	13.13	$27,768,590

REBUTTAL EXHIBIT 4

Expected Overpayment Above IP Rate in Effect from October 1, 2009 through September 30, 20011

Notes:
1. IP rates are calculated at 100 % Load Factor
2. Loads are estimated
3. Market rate forecast is as of March 16, 2009
4. Assumes a sale of all prepurchased energy at market and a purchase of IP rate power to meet load

Year	Month	Intalco Load aMW	Hours	Intalco Load MWh	Prepurchased MWh	Prepurchased $/MWh	Market Sales MWh	Market Rate $/MWh	Rate Paid	Dollars Paid	BPA Ben. $/MWh	BPA Benefit $ Paid	Actual Dollars Net $ Paid	Actual Rate $/MWh	IP Rate $/MWh	IP Dollars $ at IP Rate	Overpayment $/MWh	Overpayment $
2009	Oct	288.0	746	214,848	234,990	59.82	234,990	35.82	62.61	$ 13,451,768	$ -	$ -	$13,451,768	$62.61	36.47	$ 7,835,507	26.14	$5,616,261
	Nov	288.0	720	207,360	226,800	59.82	226,800	42.06	61.27	$ 12,703,910	$ -	$ -	$12,703,910	$61.27	41.84	$ 8,675,942	19.43	$4,027,968
	Dec	288.0	744	214,272	234,360	59.82	234,360	55.24	49.07	$ 10,514,193	$ -	$ -	$10,514,193	$49.07	44.06	$ 9,440,824	5.01	$1,073,369
2010	Jan	288.0	744	214,272	234,360	59.82	234,360	52.64	47.26	$ 10,127,164	$ -	$ -	$10,127,164	$47.26	39.41	$ 8,444,460	7.85	$1,682,705
	Feb	288.0	672	193,536	211,680	59.82	211,680	42.00	60.19	$ 11,649,053	$ -	$ -	$11,649,053	$60.19	40.70	$ 7,876,915	19.49	$3,772,138
	Mar	288.0	743	213,984	234,045	59.82	234,045	34.41	66.64	$ 14,260,362	$ -	$ -	$14,260,362	$66.64	38.85	$ 8,313,278	27.79	$5,947,083
	Apr	288.0	720	207,360	226,800	59.82	226,800	26.40	68.70	$ 14,246,280	$ -	$ -	$14,246,280	$68.70	32.15	$ 6,666,624	36.55	$7,579,656
	May	288.0	744	214,272	234,360	59.82	234,360	25.97	65.02	$ 13,932,702	$ -	$ -	$13,932,702	$65.02	28.00	$ 5,999,616	37.02	$7,933,086
	Jun	288.0	720	207,360	226,800	59.82	226,800	33.30	55.62	$ 11,532,586	$ -	$ -	$11,532,586	$55.62	26.61	$ 5,517,850	29.01	$6,014,736
	Jul	288.0	744	214,272	234,360	59.82	234,360	44.90	49.17	$ 10,535,486	$ -	$ -	$10,535,486	$49.17	32.85	$ 7,038,835	16.32	$3,496,651
	Aug	288.0	744	214,272	234,360	59.82	234,360	44.90	53.18	$ 11,394,717	$ -	$ -	$11,394,717	$53.18	36.86	$ 7,898,066	16.32	$3,496,651
	Sep	288.0	720	207,360	226,800	59.82	226,800	47.67	52.27	$ 10,838,513	$ -	$ -	$10,838,513	$52.27	38.98	$ 8,082,893	13.29	$2,755,620
	Oct	288.0	746	214,848	234,990	59.82	234,990	47.19	50.28	$ 10,803,430	$ -	$ -	$10,803,430	$50.28	36.47	$ 7,835,507	13.81	$2,967,924
	Nov	288.0	720	207,360	226,800	59.82	226,800	47.16	55.69	$ 11,547,230	$ -	$ -	$11,547,230	$55.69	41.84	$ 8,675,942	13.85	$2,871,288
	Dec	288.0	744	214,272	234,360	59.82	234,360	47.47	57.57	$ 12,335,170	$ -	$ -	$12,335,170	$57.57	44.06	$ 9,440,824	13.51	$2,894,346
2011	Jan	288.0	744	214,272	234,360	59.82	234,360	47.53	52.85	$ 11,324,744	$ -	$ -	$11,324,744	$52.85	39.41	$ 8,444,460	13.44	$2,880,284
	Feb	288.0	672	193,536	211,680	59.82	211,680	47.61	54.05	$ 10,461,528	$ -	$ -	$10,461,528	$54.05	40.70	$ 7,876,915	13.35	$2,584,613
	Mar	288.0	743	213,984	234,045	59.82	234,045	39.09	61.52	$ 13,165,031	$ -	$ -	$13,165,031	$61.52	38.85	$ 8,313,278	22.67	$4,851,753
	Apr	288.0	720	207,360	226,800	59.82	226,800	30.12	64.63	$ 13,402,584	$ -	$ -	$13,402,584	$64.63	32.15	$ 6,666,624	32.48	$6,735,960
	May	288.0	744	214,272	234,360	59.82	234,360	29.66	60.99	$ 13,067,914	$ -	$ -	$13,067,914	$60.99	28.00	$ 5,999,616	32.99	$7,068,298
	Jun	288.0	720	207,360	226,800	59.82	226,800	37.07	51.49	$ 10,677,550	$ -	$ -	$10,677,550	$51.49	26.61	$ 5,517,850	24.88	$5,159,700
	Jul	288.0	744	214,272	234,360	59.82	234,360	49.12	44.55	$ 9,546,487	$ -	$ -	$9,546,487	$44.55	32.85	$ 7,038,835	11.70	$2,507,652
	Aug	288.0	744	214,272	234,360	59.82	234,360	49.66	47.75	$ 10,232,292	$ -	$ -	$10,232,292	$47.75	36.86	$ 7,898,066	10.89	$2,334,226
	Sep	288.0	720	207,360	226,800	59.82	226,800	51.34	48.26	$ 10,006,157	$ -	$ -	$10,006,157	$48.26	38.98	$ 8,082,893	9.28	$1,923,264
sum/average		288.0	730	5,046,336	5,519,430	59.82	5,519,430	42.03	55.86	$ 281,756,851	0.0	0.0	$ 281,756,851	55.86	36.40	183,581,620	19.48	$ 98,175,231

REBUTTAL EXHIBIT 5

Overpayment Due to Improper IP-07 Rate from October 1, 2006 through September 30, 2008

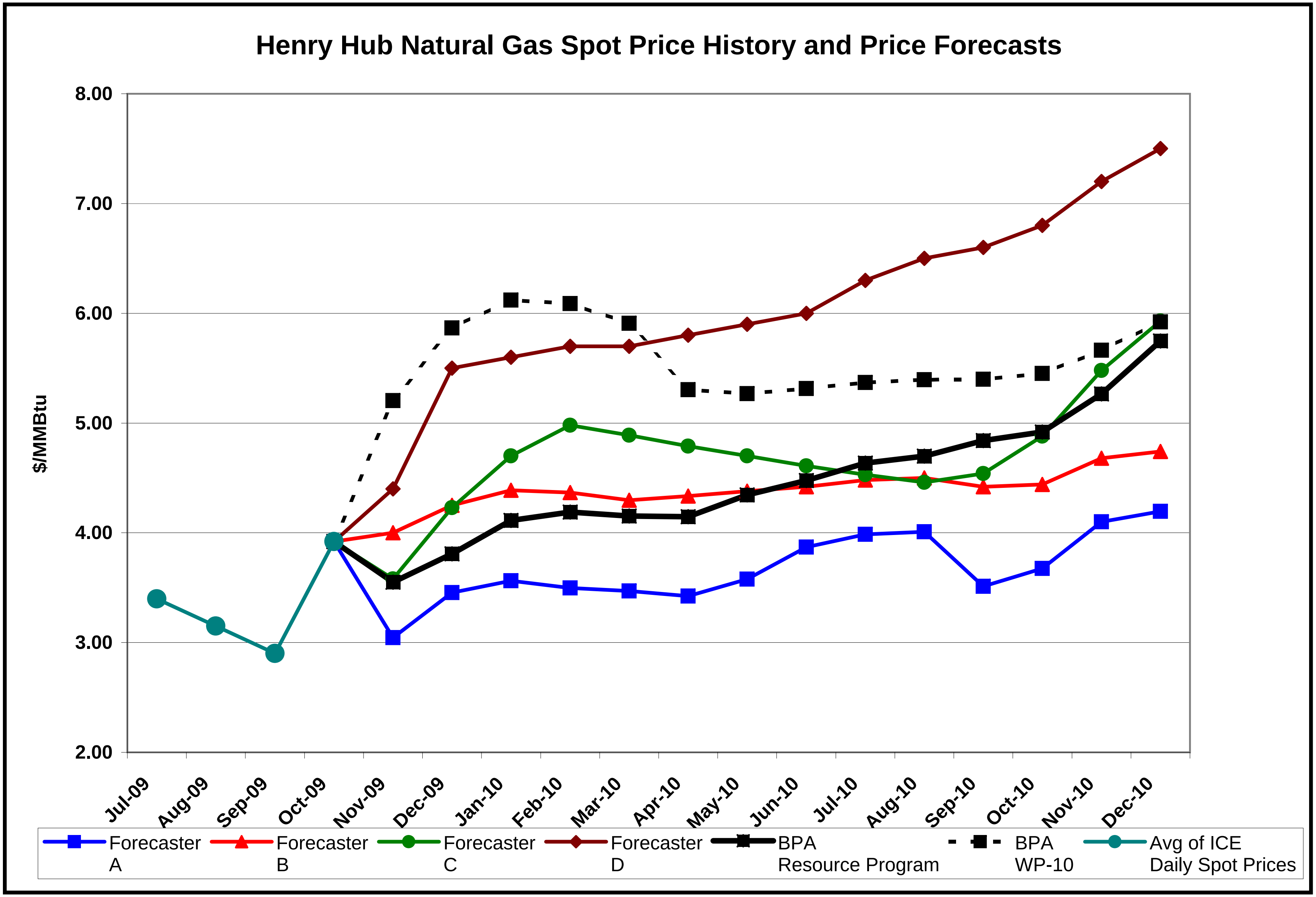
Notes: 1. IP rates are calculated at 100 % Load Factor
2. Loads are actual Intalco energy up to BPA contract limits

Year	Month	aMW	Hours	MWh	IP-07 Rate In Effect	Dollars Paid At IP-07 Rate	IP-07R Rate	Dollars Paid At IP-07R Rate	Overpaymei $/MWh	Overpayment $
2006	Oct	192.4	745	143,301	44.98	$6,445,679	36.47	$ 5,226,187	8.51	$1,219,492
	Nov	197.0	720	141,809	52.03	$7,378,322	41.84	$ 5,933,289	10.19	$1,445,034
	Dec	200.2	744	148,961	54.40	$8,103,478	44.06	$ 6,563,222	10.34	$1,540,257
2007	Jan	201.2	744	149,719	49.08	$7,348,209	39.41	$ 5,900,426	9.67	$1,447,783
	Feb	242.7	672	163,102	50.41	$8,221,972	40.70	$ 6,638,251	9.71	$1,583,720
	Mar	320.0	744	238,080	48.06	$11,442,125	38.85	$ 9,249,408	9.21	$2,192,717
	Apr	320.0	719	230,080	39.68	$9,129,574	32.15	$ 7,397,072	7.53	$1,732,502
	May	320.0	744	238,080	34.82	$8,289,946	28.00	$ 6,666,240	6.82	$1,623,706
	Jun	320.0	720	230,400	33.01	$7,605,504	26.61	$ 6,130,944	6.40	$1,474,560
	Jul	320.0	744	238,080	40.61	$9,668,429	32.85	$ 7,820,928	7.76	$1,847,501
	Aug	320.0	744	238,080	45.84	$10,913,587	36.86	$ 8,775,629	8.98	$2,137,958
	Sep	320.0	720	230,400	48.22	$11,109,888	38.98	$ 8,980,992	9.24	$2,128,896
	Oct	358.0	745	266,705	45.11	$12,031,063	36.47	$ 9,726,731	8.64	$2,304,331
	Nov	361.0	720	259,942	52.03	$13,524,782	41.84	$ 10,875,973	10.19	$2,648,809
	Dec	358.8	744	266,938	54.40	$14,521,427	44.06	$ 11,761,288	10.34	$2,760,139
2008	Jan	367.2	744	273,179	49.08	$13,407,625	39.41	$ 10,765,984	9.67	$2,641,641
	Feb	367.4	696	255,735	50.34	$12,873,700	40.70	$ 10,408,415	9.64	$2,465,285
	Mar	368.6	744	274,247	47.94	$13,147,401	38.85	$ 10,654,496	9.09	$2,492,905
	Apr	369.4	719	265,617	39.80	$10,571,557	32.15	$ 8,539,587	7.65	$2,031,970
	May	375.5	744	279,393	34.82	$9,728,464	28.00	$ 7,823,004	6.82	$1,905,460
	Jun	384.2	720	276,636	32.82	$9,079,194	26.61	$ 7,361,284	6.21	$1,717,910
	Jul	381.3	744	283,701	40.76	$11,563,653	32.85	$ 9,319,578	7.91	$2,244,075
	Aug	379.5	744	282,336	45.70	$12,902,755	36.86	$ 10,406,905	8.84	$2,495,850
	Sep	380.8	720	274,165	48.34	$13,253,136	38.98	$ 10,686,952	9.36	$2,566,184
Total/Avg				5,648,686	$ 45.10	$ 252,261,470	$ 36.40	$ 203,612,784	$ 8.70	$ 48,648,685

REBUTTAL EXHIBIT 6
SUMMARY OF OVERPAYMENTS

REBUTTAL EXHIBIT 2: OVERPAYMENTS ABOVE IP RATE IN EFFECT FROM OCTOBER 2006 THROUGH NOVEMBER 2	$	20,719,823	
REBUTTAL EXHIBIT 3: EXPECTED OVERPAYMENTS FROM DECEMBER 2008 THROUGH SEPTEMBER 2009	$	27,768,590	
REBUTTAL EXHIBIT 4: EXPECTED OVERPAYMENTS FROM OCTOBER 2009 THROUGH SEPTEMBER 2011	$	98,175,231	
SUBTOTAL OF OVERPAYMENTS IN REBUTTAL EXHIBITS 2, 3, and 4			$ 146,663,644
REBUTTAL EXHIBIT 5: OVERPAYMENTS DUE TO IMPROPPER IP-07 RATE	$	48,648,685	
TOTAL EXPECTED OVERPAYMENT BY OCTOBER 1, 2011			$ 195,312,329

ATTACHMENT E



Henry Hub Natural Gas Spot Price History and Price Forecasts
$/MMBtu
8.00
7.00
6.00
5.00
4.00
3.00
2.00
Jul-09
Aug-09
Sep-09
Oct-09
Nov-09
Dec-09
Jan-10
Feb-10
Mar-10
Apr-10
May-10
Jun-10
Jul-10
Aug-10
Sep-10
Oct-10
Nov-10
Dec-10
Forecaster A
Forecaster B
Forecaster C
Forecaster D
BPA Resource Program
BPA WP-10
Avg of ICE Daily Spot Prices

Table A-30: Federal Surplus/Deficit - By Water Year
PNW Loads and Resource Study
2009 - 2010 Fiscal Years
[59] 2010 Final Rate Case - 30 Minute Wind (Final)

7/21/2009

Energy (aMW)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
1929 Federal Surplus/Deficit	234	-71	-669	-793	-889	175	87	632	1999	981	-319	10	117
1930 Federal Surplus/Deficit	479	13	-574	-700	-936	-163	805	312	663	799	-502	-163	6
1931 Federal Surplus/Deficit	306	177	-425	-803	-827	-418	-285	1042	522	1062	158	312	73
1932 Federal Surplus/Deficit	-111	-424	-686	-1347	-1409	468	3079	5595	3928	1732	7	424	948
1933 Federal Surplus/Deficit	465	-489	330	2907	1342	-89	2013	4321	3787	3258	1979	708	1714
1934 Federal Surplus/Deficit	941	1718	2974	3255	2913	3212	4003	4593	3752	1788	-492	169	2397
1935 Federal Surplus/Deficit	297	-766	-360	2291	2697	-333	1351	3773	2549	2694	778	-119	1228
1936 Federal Surplus/Deficit	332	-137	-734	-1647	-458	-96	2070	4606	4130	1344	130	-260	775
1937 Federal Surplus/Deficit	418	269	-643	-638	-1082	-592	-1112	1632	799	422	311	129	0
1938 Federal Surplus/Deficit	390	-255	194	2372	402	1801	3667	5348	3874	2225	-300	493	1691
1939 Federal Surplus/Deficit	522	-135	-845	-623	-899	622	2251	4798	1847	946	-599	-292	641
1940 Federal Surplus/Deficit	569	283	443	-803	-542	2240	3160	3260	2944	85	-718	98	922
1941 Federal Surplus/Deficit	367	177	-95	-1066	-741	1135	395	1401	890	897	103	720	354
1942 Federal Surplus/Deficit	-59	133	640	466	533	-223	1306	3206	4502	3286	1153	303	1271
1943 Federal Surplus/Deficit	465	-473	-191	1725	2002	2404	4101	5510	3892	3121	381	-627	1857
1944 Federal Surplus/Deficit	346	-43	-761	-731	-774	-67	205	412	55	213	-6	457	-55
1945 Federal Surplus/Deficit	-53	-418	-750	-1112	-1437	-434	-1364	3585	3241	732	-138	-147	152
1946 Federal Surplus/Deficit	103	238	408	1031	-123	2929	4064	5103	3858	3050	583	392	1813
1947 Federal Surplus/Deficit	271	191	2549	2867	2576	3300	3027	4979	4284	3237	322	238	2320
1948 Federal Surplus/Deficit	2163	1930	1164	3709	1011	1631	2997	5516	3544	3908	1896	605	2520
1949 Federal Surplus/Deficit	674	1	138	-677	894	3370	3775	5471	4077	530	-548	-542	1429
1950 Federal Surplus/Deficit	352	-250	-56	1864	2671	3896	3853	4982	3464	3527	1076	404	2145
1951 Federal Surplus/Deficit	1242	1345	2889	3451	3064	3899	4007	5198	3853	3781	1128	224	2840
1952 Federal Surplus/Deficit	1692	844	1258	3733	1329	641	4444	5488	4351	2583	502	-168	2228
1953 Federal Surplus/Deficit	388	-203	-682	-181	2516	949	893	4952	4261	3912	675	261	1469
1954 Federal Surplus/Deficit	661	278	802	1691	3315	1307	2759	5496	3395	3082	3524	2187	2368
1955 Federal Surplus/Deficit	679	872	718	-362	-640	180	761	3042	3998	3178	1857	37	1204
1956 Federal Surplus/Deficit	842	1446	2756	3791	3559	3893	3846	5023	3434	3864	968	344	2812
1957 Federal Surplus/Deficit	844	-192	617	646	243	2474	3327	5721	3827	1817	-126	153	1620
1958 Federal Surplus/Deficit	388	112	-251	484	2200	1630	3046	5789	4392	1728	59	27	1625
1959 Federal Surplus/Deficit	613	638	1956	3711	3535	1815	3362	5112	3555	2381	1032	2444	2502
1960 Federal Surplus/Deficit	2681	2749	2255	2720	1052	2002	3911	4241	4338	2506	143	320	2415
1961 Federal Surplus/Deficit	491	-96	-194	2007	1295	2577	2822	5430	3937	2188	552	-120	1744
1962 Federal Surplus/Deficit	105	133	308	1198	1136	327	3460	4883	4522	1203	130	-156	1433
1963 Federal Surplus/Deficit	1075	852	1765	1921	1837	-104	1513	3985	4509	2846	805	277	1770
1964 Federal Surplus/Deficit	152	10	204	220	962	-167	1000	4403	4228	3692	1539	945	1432
1965 Federal Surplus/Deficit	1201	703	2799	3875	3453	3845	3369	5534	4726	2374	1493	455	2817
1966 Federal Surplus/Deficit	782	-51	123	1557	230	-419	3199	3836	3293	2819	637	-82	1331
1967 Federal Surplus/Deficit	260	-239	308	3424	3750	1761	799	4005	3984	3946	1152	403	1953
1968 Federal Surplus/Deficit	590	-86	296	2317	2130	1818	464	2884	4004	3856	1458	1532	1770
1969 Federal Surplus/Deficit	1251	1572	1308	3771	3994	2157	3835	5347	4103	3559	167	68	2583
1970 Federal Surplus/Deficit	703	154	-420	-136	1824	1444	1447	3794	4712	2107	-162	-153	1267
1971 Federal Surplus/Deficit	357	57	56	3762	3785	3869	4096	5219	3758	3733	2128	577	2609
1972 Federal Surplus/Deficit	829	133	523	3759	3846	3418	3451	5236	3576	3173	2933	726	2629
1973 Federal Surplus/Deficit	675	72	875	480	-571	118	-231	2546	1379	895	-674	-262	451
1974 Federal Surplus/Deficit	294	-558	1930	3595	3310	3655	3901	5149	3586	3262	1943	371	2536
1975 Federal Surplus/Deficit	88	-93	-340	1184	1017	2433	1056	5397	3992	3839	739	724	1677
1976 Federal Surplus/Deficit	1384	1705	3312	3502	3689	3090	4163	5411	4305	3636	3934	3097	3435
1977 Federal Surplus/Deficit	699	52	-628	-724	-556	-11	-564	-192	-468	328	241	291	-125
1978 Federal Surplus/Deficit	-551	-588	894	932	557	1424	3282	4768	3473	2784	428	1610	1587
1979 Federal Surplus/Deficit	855	171	-504	-442	771	2213	1296	4586	1203	580	-685	-296	814
1980 Federal Surplus/Deficit	338	145	321	-1279	175	67	2203	5607	4378	1537	-231	260	1127
1981 Federal Surplus/Deficit	426	271	2420	3523	1894	1613	834	3497	4059	4072	2416	261	2115
1982 Federal Surplus/Deficit	542	444	382	2445	3950	3493	3727	5664	4065	3498	1897	1451	2618
1983 Federal Surplus/Deficit	1392	652	882	3259	1646	3806	3623	4891	4274	4055	1846	709	2594
1984 Federal Surplus/Deficit	685	2149	484	3673	1250	4151	4631	3991	4648	4024	732	618	2590
1985 Federal Surplus/Deficit	594	637	273	916	-844	1657	3705	4901	2035	318	-990	-54	1106
1986 Federal Surplus/Deficit	604	1197	-526	1895	2706	4058	3938	3366	3693	2179	285	-215	1920
1987 Federal Surplus/Deficit	149	509	-290	-723	-433	781	1657	2962	2979	945	-617	-399	628
1988 Federal Surplus/Deficit	160	-61	-1007	-1002	-989	-321	464	2154	53	1387	138	-8	88
1989 Federal Surplus/Deficit	-34	-403	-288	-1114	-202	1210	3903	4414	2546	678	-817	-147	813
1990 Federal Surplus/Deficit	282	207	1083	2667	1598	1259	3798	3940	4048	2065	810	-254	1790
1991 Federal Surplus/Deficit	-2	1476	1333	3482	3452	930	2622	5148	4035	3577	1784	-26	2309
1992 Federal Surplus/Deficit	193	-279	-939	-585	-980	1748	547	1840	890	645	-712	-509	164
1993 Federal Surplus/Deficit	199	-91	-553	-699	-802	199	644	4159	1653	1560	324	-538	515
1994 Federal Surplus/Deficit	172	329	-44	-771	-400	-141	1204	2247	1271	985	-633	-389	321
1995 Federal Surplus/Deficit	95	-367	-227	-29	1783	2964	1882	3906	3605	2603	189	183	1378
1996 Federal Surplus/Deficit	916	2716	3290	3431	2971	3374	3785	5563	4532	3903	1473	285	3019
1997 Federal Surplus/Deficit	570	52	1256	3528	3518	3589	3866	5209	3815	3672	1664	1553	2686
1998 Federal Surplus/Deficit	2718	1109	199	2093	1448	1793	1711	4278	4298	2656	391	149	1906
Ranked Averages													
Top Ten Percent	998	1157	2404	3619	3443	3587	3784	5311	4034	3486	1942	955	2891
Middle Eighty Percent	556	281	409	1289	1201	1599	2479	4409	3533	2397	538	257	1580
Bottom Ten Percent	377	48	-673	-770	-865	-199	-57	856	518	742	3	147	15
DSI Augmentation	402	402	402	402	402	402	402	402	402	402	402	402	402
Less DSI Augmentation	154	-121	7	887	799	1197	2077	4007	3131	1995	136	-145	1178

Table A-30: Federal Surplus/Deficit - By Water Year
PNW Loads and Resource Study
2010 - 2011 Fiscal Years **7/21/2009**
[59] 2010 Final Rate Case - 30 Minute Wind (Final)

Energy (aMW)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
1929 Federal Surplus/Deficit	399	91	-496	-623	-716	352	-305	38	1404	1044	9	174	117
1930 Federal Surplus/Deficit	644	175	-401	-530	-765	14	414	-282	68	862	-173	0	6
1931 Federal Surplus/Deficit	471	339	-252	-633	-654	-241	-679	449	-72	1126	487	476	74
1932 Federal Surplus/Deficit	54	-262	-513	-1178	-1237	643	2914	5550	4086	1795	336	588	1075
1933 Federal Surplus/Deficit	631	-328	504	3065	1516	87	1623	3735	3943	3500	2311	872	1791
1934 Federal Surplus/Deficit	1107	1866	3634	3895	3781	3367	4390	4009	3125	1853	-163	332	2591
1935 Federal Surplus/Deficit	462	-605	-186	2457	2840	-156	959	3186	1956	2761	1108	44	1226
1936 Federal Surplus/Deficit	497	25	-561	-1478	-285	80	1679	4019	3963	1407	460	-96	811
1937 Federal Surplus/Deficit	583	432	-470	-467	-909	-415	-1506	1039	203	484	641	293	0
1938 Federal Surplus/Deficit	555	-93	368	2538	574	1978	3568	5248	3283	2289	29	657	1757
1939 Federal Surplus/Deficit	687	27	-672	-452	-727	799	1861	4212	1254	1009	-271	-129	642
1940 Federal Surplus/Deficit	734	446	618	-633	-371	2418	2770	2673	2353	147	-389	262	923
1941 Federal Surplus/Deficit	532	340	78	-854	-620	1313	3	809	294	960	433	885	354
1942 Federal Surplus/Deficit	105	295	813	637	706	-46	914	2618	3911	3353	1484	467	1273
1943 Federal Surplus/Deficit	631	-312	-18	1889	2151	2581	4640	4918	3937	3185	710	-465	1984
1944 Federal Surplus/Deficit	510	119	-588	-560	-601	111	-187	-182	-542	274	323	622	-56
1945 Federal Surplus/Deficit	111	-256	-577	-942	-1267	-257	-1758	2996	2648	794	191	16	152
1946 Federal Surplus/Deficit	268	400	582	1202	49	3099	4030	5071	3266	3116	913	556	1890
1947 Federal Surplus/Deficit	435	353	2716	3032	2725	3463	2637	4385	4164	3304	651	401	2355
1948 Federal Surplus/Deficit	2310	2094	1339	4258	581	1809	2695	5481	3695	4144	2228	769	2635
1949 Federal Surplus/Deficit	839	162	312	-507	1067	3523	3773	5241	3846	592	-219	-379	1519
1950 Federal Surplus/Deficit	517	-88	117	2029	2820	4364	3487	4384	3623	3704	1406	567	2241
1951 Federal Surplus/Deficit	1407	1508	3049	4462	3941	4400	4452	5049	3262	3968	1458	388	3109
1952 Federal Surplus/Deficit	1850	1006	1432	3891	1493	818	4305	5454	4228	2648	832	-5	2334
1953 Federal Surplus/Deficit	553	-41	-509	-11	2665	1126	501	4363	4418	4092	1005	425	1540
1954 Federal Surplus/Deficit	826	440	976	1856	3457	1484	2368	4957	3557	3324	3858	2336	2447
1955 Federal Surplus/Deficit	844	1035	892	-191	-468	358	369	2454	4155	3420	2189	200	1282
1956 Federal Surplus/Deficit	1007	1609	2915	4751	3301	4047	3920	4988	3602	4050	1298	507	3002
1957 Federal Surplus/Deficit	1009	-31	791	818	416	2651	2937	5533	3997	1881	202	316	1718
1958 Federal Surplus/Deficit	552	274	-78	655	2349	1808	2656	5535	4449	1792	389	190	1706
1959 Federal Surplus/Deficit	778	800	2123	4475	3670	1263	2943	4413	3722	2446	1365	2593	2538
1960 Federal Surplus/Deficit	2824	2889	2422	2886	1226	2180	3893	3655	4231	2572	473	484	2482
1961 Federal Surplus/Deficit	657	65	-20	2173	1443	2756	2432	4837	3694	2253	882	43	1772
1962 Federal Surplus/Deficit	270	295	482	1370	1309	504	3587	4298	4411	1266	459	7	1516
1963 Federal Surplus/Deficit	1240	1014	1932	2088	1986	72	1123	3397	3947	2912	1135	441	1772
1964 Federal Surplus/Deficit	316	172	378	392	1136	10	607	3817	4382	3933	1871	1110	1510
1965 Federal Surplus/Deficit	1367	866	2966	4837	4407	3999	3574	5190	4457	2439	1824	618	3040
1966 Federal Surplus/Deficit	947	111	297	1729	403	-243	3103	3250	2702	2886	967	81	1357
1967 Federal Surplus/Deficit	425	-77	483	4200	3747	1144	359	3411	3610	4190	1483	568	1953
1968 Federal Surplus/Deficit	755	76	470	2483	2279	1997	73	2295	3913	3924	1789	1689	1810
1969 Federal Surplus/Deficit	1417	1735	1483	4596	3647	2055	4446	5245	3880	3627	497	232	2730
1970 Federal Surplus/Deficit	868	316	-247	33	1974	1622	1056	3207	4763	2170	167	10	1319
1971 Federal Surplus/Deficit	521	219	230	4334	4461	3914	3727	5182	3917	3972	2460	741	2797
1972 Federal Surplus/Deficit	995	294	697	4223	4038	4997	3482	5200	3733	3415	3266	890	2933
1973 Federal Surplus/Deficit	840	234	1049	650	-399	295	-623	1957	784	958	-346	-99	452
1974 Federal Surplus/Deficit	459	-397	2097	4401	3932	5015	4343	5109	3753	3504	2275	535	2918
1975 Federal Surplus/Deficit	253	70	-167	1348	1191	2611	665	4804	4151	4078	1068	888	1753
1976 Federal Surplus/Deficit	1550	1868	3966	4435	4099	2549	4234	5297	4147	3877	4284	3248	3628
1977 Federal Surplus/Deficit	864	214	-454	-553	-383	167	-957	-785	-1063	391	572	455	-124
1978 Federal Surplus/Deficit	-387	-427	1058	1103	729	1601	2877	4174	2881	2849	758	1759	1585
1979 Federal Surplus/Deficit	1021	333	-330	-271	945	2391	905	3999	608	642	-356	-132	815
1980 Federal Surplus/Deficit	504	308	495	-1088	324	243	1812	5399	3787	1600	98	424	1160
1981 Federal Surplus/Deficit	592	433	2588	4393	1035	1785	417	2892	4219	4316	2749	425	2170
1982 Federal Surplus/Deficit	708	606	555	2611	4502	4963	3182	5370	3670	3563	2228	1605	2786
1983 Federal Surplus/Deficit	1557	815	1056	3416	1794	5168	3217	4297	3681	4122	2178	873	2691
1984 Federal Surplus/Deficit	850	2296	657	4446	639	4501	4122	3403	4796	4091	1061	782	2646
1985 Federal Surplus/Deficit	759	799	447	1088	-673	1836	3298	4315	1441	380	-663	109	1105
1986 Federal Surplus/Deficit	769	1360	-352	2059	2842	4802	3842	2777	3100	2244	614	-52	1990
1987 Federal Surplus/Deficit	313	671	-116	-553	-260	959	1267	2374	2389	1008	-288	-236	629
1988 Federal Surplus/Deficit	325	102	-834	-831	-816	-144	72	1565	-543	1451	467	156	88
1989 Federal Surplus/Deficit	131	-242	-114	-944	-30	1387	3581	3828	1954	740	-489	17	819
1990 Federal Surplus/Deficit	447	369	1259	2833	1773	1437	3850	3354	4199	2129	1141	-90	1889
1991 Federal Surplus/Deficit	163	1640	1508	3963	3542	606	2225	4560	3445	3818	2116	138	2303
1992 Federal Surplus/Deficit	358	-118	-767	-414	-808	1927	156	1248	296	708	-383	-346	164
1993 Federal Surplus/Deficit	365	71	-379	-528	-630	374	251	3570	1056	1623	653	-375	515
1994 Federal Surplus/Deficit	337	492	130	-601	-227	36	813	1658	678	1049	-305	-225	322
1995 Federal Surplus/Deficit	260	-205	-53	142	1931	3119	1491	3318	3012	2668	519	347	1375
1996 Federal Surplus/Deficit	1081	2864	3933	4477	3832	4732	4138	5391	4682	4144	1804	448	3459
1997 Federal Surplus/Deficit	736	214	1430	4267	4270	4946	4101	5174	3974	3912	1995	1707	3054
1998 Federal Surplus/Deficit	2860	1272	372	2257	1613	1971	1321	3681	4453	2722	720	313	1965
Ranked Averages													
Top Ten Percent	1163	1318	2708	4493	3984	4239	3986	5184	3980	3686	2276	1115	3175
Middle Eighty Percent	719	442	591	1554	1344	1815	2209	3927	3280	2501	868	419	1640
Bottom Ten Percent	542	210	-499	-600	-692	-22	-450	263	-78	805	332	311	15
DSI Augmentation	402	402	402	402	402	402	402	402	402	402	402	402	402
Less DSI Augmentation	317	40	189	1152	942	1413	1807	3525	2878	2099	466	17	1238

ATTACHMENT F

ADMINISTRATOR'S RECORD OF DECISION

SHORT-TERM MARKETING AND OPERATING ARRANGEMENTS

INTRODUCTION

The Bonneville Power Administration (BPA) has decided to enter into short-term marketing and operational arrangements in order to participate continuously in the open electric power market. These arrangements would enable BPA to achieve the best reliability and expected economic outcome, as well as to best meet its environmental responsibilities, given diverse market conditions. This decision would support power cost control, enhance BPA competitiveness, and provide public benefits. The amount of hydropower available to BPA will be defined by the System Operation Review (SOR), a separate process underway to determine future hydro operations. The decision documented in this Record of Decision (ROD) is a direct application of BPA's earlier decision to use a Market-Driven approach for participation in the increasingly competitive electric power market.

The decision to enter into these short-term contractual arrangements is consistent with BPA's Business Plan, the Business Plan Environmental Impact Statement (BP EIS) (DOE/EIS-0183, June 1995) and the BP ROD (August 15, 1995). In response to a need for a sound policy to guide its business direction under changing market conditions, BPA explored six alternative plans of action in its BP EIS. The six alternatives were: Status Quo (no action), BPA Influence, Market-Driven, Maximize Financial Returns, Minimal BPA, and Short-Term Marketing. In the subsequent BP ROD, the BPA Administrator selected the Market-Driven Alternative. Although the Status Quo and the BPA Influence alternatives were environmentally preferred, the differences in total environmental impacts among alternatives were relatively small. Other business aspects, including loads and rates, showed greater variation among the alternatives. The Market-Driven Alternative strikes a balance between marketing and environmental concerns. It also helps BPA to ensure the financial strength necessary to maintain high level of support for public benefits such as energy conservation and fish and wildlife mitigation activities.

The BP EIS and ROD were also intended to guide BPA in a series of related decisions on specific issues and actions. Decisions on providing short-term marketing and operational arrangements are some of these subsequent actions, and the subject of this tiered ROD. Tiering subsequent RODs to the BP ROD helps delineate BPA decisions clearly and provides a logical framework for connecting broad programmatic decisions to more specific actions.

Before taking specific action on any of these issues, BPA affirmatively stated that it would review the BP EIS to ensure that a particular action was adequately covered within the scope of that EIS and, if appropriate, issue a tiered ROD. This ROD, which summarizes and incorporates information from the BP ROD, is a result of such a review. It describes specific information on the decision to provide short-term marketing and operational arrangements, and summarizes the environmental impacts associated with this decision, as described in the BP EIS.

NEW COMPETITIVENESS IN THE ELECTRIC INDUSTRY

The electric utility industry is becoming increasingly competitive and dynamic. Four factors are substantially affecting BPA's ability to compete: market change, increased non-power obligations, deterioration of BPA's cost/price advantage, and lost hydro output. The emergence of competition has led to significantly lower prices for wholesale electric power. At the same time, BPA's costs for providing major public benefits (including fish and wildlife enhancement and support of energy efficiency) have increased significantly. A series of dry years and changes in hydro system operations have also seriously affected BPA's ability to produce power and generate revenues.

The current West Coast surplus, decline in costs of competing generating resources, low cost of energy, and difficulty in siting and developing new generating facilities continue to lead electric utilities and other parties to emphasize shorter-term commitments to buy and sell. In addition, the recent market deregulation has fostered the emergence of marketers and broker parties. These parties by their nature concentrate on shorter-term commitments than do utilities that have extended obligations to serve load.

However, BPA must be able to balance its costs and revenues. The availability of power at competitive prices from other suppliers prevents BPA from meeting costs simply by raising rates for its customers. That BPA firm power rate level above which a rate increase would no longer increase BPA's revenue and cover BPA's costs would produce BPA's maximum sustainable revenue. Allowing BPA's rates to exceed this level would not be consistent with sound business principles. BPA's total revenue would be reduced, as would BPA's ability to fund public benefits.

SHORT-TERM MARKETING CUSTOMERS

BPA will negotiate short-term marketing and operating arrangements and related transmission services with parties able to participate in the open electric power market. Potential customers include utilities and Direct Service Industries within the region, and other power purchasers inside and outside the Pacific Northwest (PNW).

DESCRIPTION OF THE PROPOSED SHORT-TERM MARKETING AND OPERATIONAL ARRANGEMENTS AND RELATED TRANSMISSION ARRANGEMENTS

Short-Term Marketing

BPA will continuously participate in the bulk electric power market via its short-term marketing arrangements. Short-term marketing and operating arrangements cover a variety of scheduling periods--hours, weeks, days, months, or years. The vast majority of these market-based actions cover periods of less than 1 year, although some actions could have terms of up to 5 years.

BPA's short-term marketing actions will try to maximize the value of hydrosystem conditions that result from decisions made by other agencies. (As noted earlier, the amount of hydropower available to BPA will be defined by the SOR. Decisions made by the Corps of Engineers or Bureau of Reclamation to manage river operations for navigation, flood control, irrigation, recreation and fish and wildlife activities determine how much water is available for generation and when it is available.) Maximizing hydrosystem value can take a number of forms. For example, throughout the late spring and summer months, BPA sells very large amounts of surplus energy generated from flow provided for downstream salmon migration, as prescribed by the National Marine Fisheries Service 1995 Biological Opinion. During the fall, BPA often purchases large quantities of energy to recover depleted reservoirs, in preparation for winter loads. BPA also makes purchases to meet extreme weather conditions and unexpected resource or transmission outages.

The peak load demands of the PNW and California occur at different times. The PNW peaks occur in winter, while California's demand peaks in summer. During the summer, the PNW hydro-based systems tend to have excess capacity that can be used to help meet California's peak demands. Similarly, California's thermal-based system tends to have excess capacity in the winter, which can be used to help the PNW meet its peak demands. BPA has several seasonal and capacity/energy exchange contracts with California utilities.

In general, BPA will be in the market buying or selling to match energy supplies to load and/or to execute operational strategies. To the extent permitted by statute and consistent with sound business principles, BPA will also expand its short-term marketing activity beyond the disposal of surplus generation or the meeting of short-term load. BPA will look continuously for marketing opportunities in power-related trading and financial transactions. BPA's objective will be to improve net revenues, reduce costs, and reduce the risk of periodic revenue shortfalls due to changes in supply or market conditions.

Water Management

The Power Supply Manager may arrange for water storage, rentals or other physical water management operations for fish-related or other non-power purposes; for energy storage as a service to other utilities; and for implementation actions related to the Pacific Northwest Coordination Agreement, the Columbia River Treaty annual operating plan or detailed operating plan, and non-Treaty coordination operations such as the Non-Treaty Storage Agreement.

ENVIRONMENTAL ANALYSIS

Consistent with the BP ROD, the Administrator reviewed the BP EIS to determine whether (1) entering into short-term (5 years or less) marketing and operational arrangements in order to participate continuously in the open electric power market and (2) making generation operation decisions that accommodate that participation were adequately covered within the scope of the BP EIS. The BP EIS was intended to support a number of decisions, including short-term contractual arrangements lasting 5 years or less. The chosen Market-Driven Alternative includes the offering of flexible short-term arrangements with customers. In addition, one of the other alternatives analyzed in the EIS, Short-Term Marketing, limited BPA's marketing activities to short-term marketing of power and transmission products and services.

The BP EIS showed that environmental impacts are determined by the responses to BPA's marketing actions, rather than by the actions themselves. These market responses include resource development, resource operation, transmission development and operation, and consumer behavior.

Environmental Impacts

Short-term marketing and operating arrangements are an integral part of the marketing efforts of a Market-Driven BPA. As such, the potential impacts on resource development, resource operations, transmission system development and operations, and consumer behavior were considered in determining the potential environmental impacts of adopting a Market-Driven approach to participation in the competitive electric utility market.

Regionally, fewer new resources (most likely combustion turbines) would be developed because less load would be shifted away from BPA. However, the operation of existing generation would be greater, as other participants compete within the utility market. The higher emissions levels of these mostly older, less-efficient thermal resources would result in higher levels of air emissions and water use. Transmission system development would be unchanged; transmission system operation would likely be more efficient. BPA rates would be competitive with market rates.

Marketing Impacts

The expected broad marketing impacts of BPA's adopted approach will be (1) to preserve or increase BPA's market share in the PNW and West Coast open markets as much as possible, given the deregulated and competitive nature of the market, (2) to maximize BPA's power operations efficiency, in context with non-power objectives, and (3) mutually to benefit BPA's power economics and power system operations through coordinated short-term trading and risk management arrangements. Many of BPA's customers and other parties participating in the open market are expected to respond to BPA's short-term marketing and operating arrangement efforts. Flexible contracts responding to the pricing and unbundling forces emerging with the opening of the wholesale power market will meet customer needs for competitively priced products and services, improve customer relations, assist BPA in reducing costs, and enhance BPA's ability to use a Market-Driven approach to participate continuously in the open electric market. Systematic efforts to meet customer needs, offer feasible service options, and lower rates will help BPA to continue to serve the bulk of its historic loads. Load will be lost mainly as customers seek ways to diversify their sources of power, and not through dissatisfaction with BPA. To the extent that BPA is successful in applying a Market-Driven approach to its business activities, BPA will be more likely to maintain revenues and be better able to fund public benefits.

Public Benefits

Consistent with the Market-Driven approach, the decision to undertake short-term contractual arrangements lasting 5 years or less strikes a balance between marketing and environmental concerns. BPA will actively participate in the competitive market for power, and will use its success in the market to ensure the financial strength necessary to produce the public benefits that BPA affords to the region.

Mitigation

In deciding to enter into these short-term contractual arrangements under the Market-Driven approach, BPA understands that the conditions that permit the agency to function successfully may change over time. Therefore, the Market-Driven Alternative contains preparatory mitigation measures (response strategies) to respond to change and allow the agency to balance cost and revenues. Such mitigation will enhance BPA's ability to adapt to changing market conditions.

These response strategies--which include means to decrease spending, increase revenues, and transfer costs--could be implemented if BPA's costs and revenues did not balance. BPA has already decided (in the BP ROD) to apply as many mitigation response strategies as necessary whenever BPA's costs and revenues do not balance. These mitigation strategies, or equivalents, will be implemented to enable BPA to best meet its public service and environmental obligations, while remaining competitive in the wholesale electric power market.

PUBLIC AVAILABILITY

Copies of the Business Plan EIS and the Business Plan ROD, as well as additional copies of this ROD, are available to all interested and affected persons and agencies from BPA's Public Involvement Office, P.O. Box 12999, Portland, Oregon 97212. Copies of these documents may also be obtained by using BPA's nationwide toll-free request line, 1-800-622-4520.

CONCLUSION

I have decided that BPA will enter into short-term marketing and operational arrangements (consistent with the SOR) in order to participate continuously in the open electric power market.

This decision is consistent with BPA's Market-Driven approach for participation in the increasingly competitive power market, since it will enable BPA to increase the value of its short-term power products, increase net revenues, and control costs. BPA seeks to be responsive to its customers' needs, while ensuring the financial strength necessary to produce public benefits such as fish and wild life mitigation and energy conservation.

Issued in Portland, Oregon, on January 22, 1996.

/s/ Randall W. Hardy
Administrator and Chief
Executive Officer

bcc:
Adm. Chron. File – A

Official File - KEC (EQ-14 – Business Plan EIS – 1996)

KPierce:ljc:1/19/96

Original Electronic File:
W\ECN\ECN96\EQ-14\BPEIS\STMARROD.doc)

This Electronic File:
W\KEC\EISs – EQ-14\Business Plan\All Finalized BP RODs\
Short-Term Marketing ROD 1-22-96.doc

ATTACHMENT G

BPA's Re-creation of Snohomish Analysis

Snohomish Public Utility District asserted in its October 19th comment that:

> "Calendar year 2010 physical energy prices for the Mid-Columbia Market Hub are higher than BPA's revised market forecast [see Attachment A]. Snohomish estimates a forward sale at market would generate $2.47 million more than from the same sale at the IP rate. We therefore conclude a forward sale at market provides greater financial benefit to BPA." (See Snohomish at 2)

BPA has re-created Snohomish's analysis based on market prices from November 6th to illustrate that individual forward market price observations can be a volatile indicator to employ in longer-term public policy decisions. Specifically, BPA developed the following described below and presented on the subsequent pages:

1) Figure 1 was re-created just as Snohomish presented in its October 19th comment with prices from October 15, 2009
2) Figure 2 was re-created illustrating all of the inputs, including BPA's Nov-09 and Dec-09 prices from TFS, BPA's estimation of TFS light load hour (LLH) pricing since LLH prices are not published by TFS, and the Flat Average forward price for the period
3) Figure 3 was re-created continuing to illustrate all of the inputs from Figure 2, using BPA's market price inputs from TFS for November 6, 2009, BPA's estimation of TFS LLH market pricing for November 6, 2009, and the Flat Average forward price for the period

Figure 1 – Snohomish's Attachment A

Attachment A: Mid-C Electricity Prices and Revenue Comparison
Version 1: as submitted by SnoPUD in Oct 19th comment

Mid-Columbia Energy Prices	HLH	LLH		**BPA Revised Market Forecast**	HLH Price ($ / MWh)	LLH Price ($ / MWh)
Q1 - 2010	$49.50	$43.50	BPA does not agree	**Jan-10**	$34.13	$29.51
				Feb-10	$34.46	$29.77
				Mar-10	$33.92	$29.16
Q2 - 2010	$39.00	$27.00	BPA does not agree	**Apr-10**	$32.95	$28.05
				May-10	$33.93	$24.45
				Jun-10	$34.33	$26.33
Q3 - 2010	$58.25	$42.25	BPA does not agree	**Jul-10**	$37.33	$32.18
				Aug-10	$42.48	$35.63
				Sep-10	$42.86	$38.00
Q4 - 2010	$59.25	$50.75	BPA does not agree	**Oct-10**	$43.31	$36.85
				Nov-10	$45.36	$40.59
				Dec-10	$48.81	$43.42

Port Townsend Revenue Comparison Nov. 2009 - Dec. 2010	
Estimated BPA revenues based on the IP rate	$7,104,839
Estimated BPA revenues based on BPA's revised market forecast	$6,997,593
Difference between revenue at the IP rate and BPA's revised market forecast	$107,246
Estimated BPA revenues based on sale at Mid-Columbia Power Prices	$9,588,434
Difference between revenues at the IP rate and Mid-C Power Sale at Market Prices	($2,483,595)

Figure 2 – BPA's re-creation of Snohomish's Attachment A

Attachment A: Mid-C Electricity Prices and Revenue Comparison
Version 2: as adjusted by BPA using Oct 15th market prices

Mid-Columbia Energy Prices	HLH	LLH	Source	BPA Revised Market Forecast	HLH Price ($ / MWh)	LLH Price ($ / MWh)
Nov	$45.50	**$39.42**	not provided	**Nov-09**	$28.75	$26.38
Dec	$55.50	**$47.98**	not provided	**Dec-09**	$30.61	$27.41
Q1 - 2010	$49.50	**$43.87**	changed; derived LLH	**Jan-10**	$34.13	$29.51
				Feb-10	$34.46	$29.77
				Mar-10	$33.92	$29.16
Q2 - 2010	$39.00	**$25.93**	changed; derived LLH	**Apr-10**	$32.95	$28.05
				May-10	$33.93	$24.45
				Jun-10	$34.33	$26.33
Q3 - 2010	$58.25	**$41.80**	changed; derived LLH	**Jul-10**	$37.33	$32.18
				Aug-10	$42.48	$35.63
				Sep-10	$42.86	$38.00
Q4 - 2010	$59.25	**$50.07**	changed; derived LLH	**Oct-10**	$43.31	$36.85
				Nov-10	$45.36	$40.59
				Dec-10	$48.81	$43.42
Flat Average		**$46.78**				

Port Townsend Revenue Comparison Nov. 2009 - Dec. 2010

Estimated BPA revenues based on the IP rate	$7,104,839
Estimated BPA revenues based on BPA's revised market forecast	**$6,997,512**
Difference between revenue at the IP rate and BPA's revised market forecast	$107,327
Estimated BPA revenues based on sale at Mid-Columbia Power Prices	$9,567,039
Difference between revenues at the IP rate and Mid-C Power Sale at Market Prices	($2,462,200)

BPA's addition to clarify results provided by Snohomish (yellow)
BPA's adjustment to values provided by Snohomish (pink)

Figure 3 – BPA's re-creation of Snohomish's Attachment A using Nov 6th price data

Attachment A: Mid-C Electricity Prices and Revenue Comparison
Version 3: as adjusted by BPA using Nov 6th market prices

Mid-Columbia Energy Prices	HLH	LLH	Source	BPA Revised Market Forecast	HLH Price ($ / MWh)	LLH Price ($ / MWh)
Nov	$36.63	**$30.00**	ICE (avg bid / ask)	**Nov-09**	$28.75	$26.38
Dec	$43.50	**$36.98**	HLH = TFS avg; LLH = derived	**Dec-09**	$30.61	$27.41
Q1 - 2010	$42.00	**$36.95**	HLH = TFS avg; LLH = derived	**Jan-10**	$34.13	$29.51
				Feb-10	$34.46	$29.77
				Mar-10	$33.92	$29.16
Q2 - 2010	$32.50	**$21.06**	HLH = TFS avg; LLH = derived	**Apr-10**	$32.95	$28.05
				May-10	$33.93	$24.45
				Jun-10	$34.33	$26.33
Q3 - 2010	$52.50	**$37.29**	HLH = TFS avg; LLH = derived	**Jul-10**	$37.33	$32.18
				Aug-10	$42.48	$35.63
				Sep-10	$42.86	$38.00
Q4 - 2010	$53.50	**$45.77**	HLH = TFS avg; LLH = derived	**Oct-10**	$43.31	$36.85
				Nov-10	$45.36	$40.59
				Dec-10	$48.81	$43.42
Flat Average		**$40.30**				

Port Townsend Revenue Comparison Nov. 2009 - Dec. 2010	
Estimated BPA revenues based on the IP rate	$7,104,839
Estimated BPA revenues based on BPA's revised market forecast	**$6,997,512**
Difference between revenue at the IP rate and BPA's revised market forecast	$107,327
Estimated BPA revenues based on sale at Mid-Columbia Power Prices	$8,242,213
Difference between revenues at the IP rate and Mid-C Power Sale at Market Prices	($1,137,374)

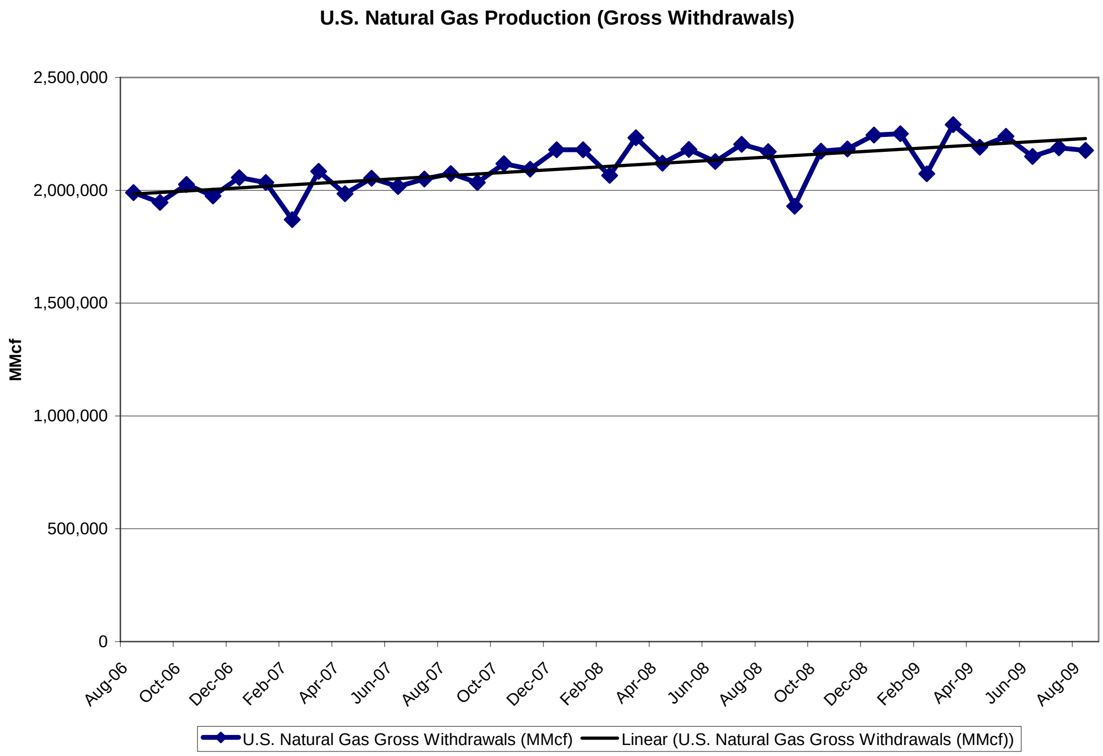
Legend	
(yellow)	BPA's addition to clarify results provided by Snohomish
(pink)	BPA's adjustment to values provided by Snohomish

BPA's re-creation of Snohomish's analysis using BPA's market price inputs from TFS and BPA's estimation of TFS LLH market pricing for November 6, 2009 reduces Snohomish's estimate of the difference between revenues at the IP rate and Mid-C power sale at market prices from $2.5 million to $1.1 million. In the short passage of time, just three weeks from October 15th to November 6th, the flat average of the forward prices observed by BPA for the 14-month term of the Block Contract fell from $46.78 per MWh to $40.30 per MWh and reduced the cost asserted by Snohomish by more than half. This contributes to why BPA believes individual forward market price observations can be a volatile indicator and, as a result, a poor tool to employ in longer-term public policy decisions.

ATTACHMENT H

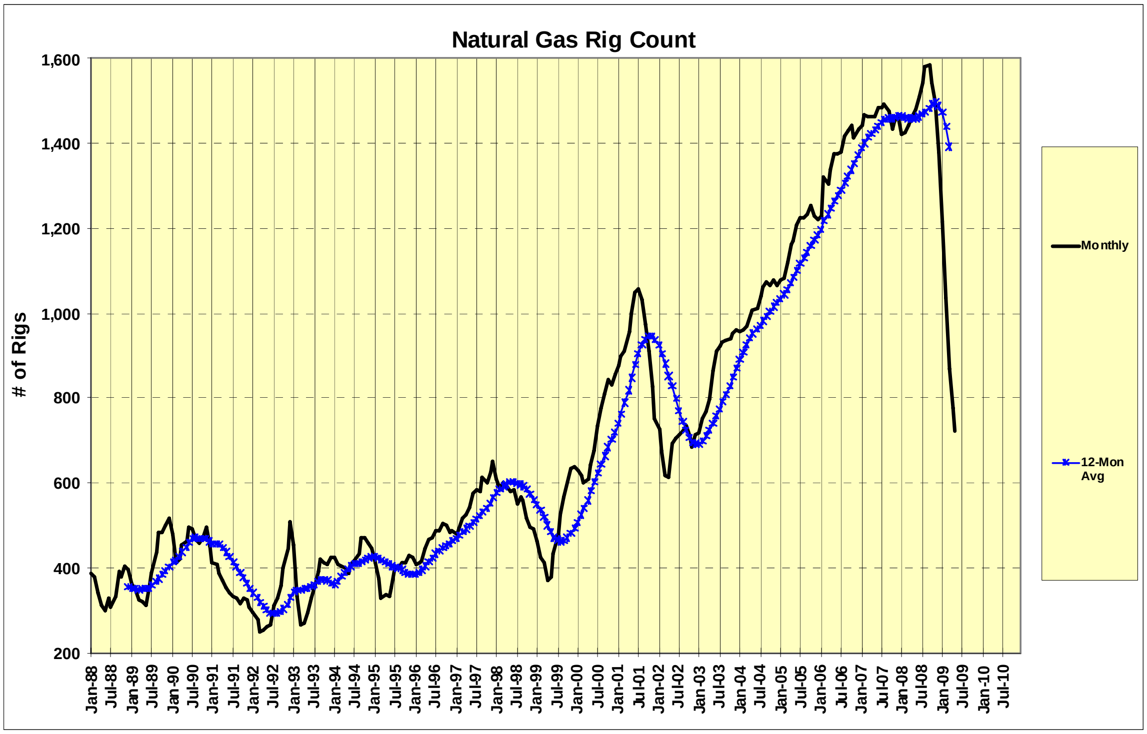
Natural Gas Statistics

Figure 1 – Natural Gas Production



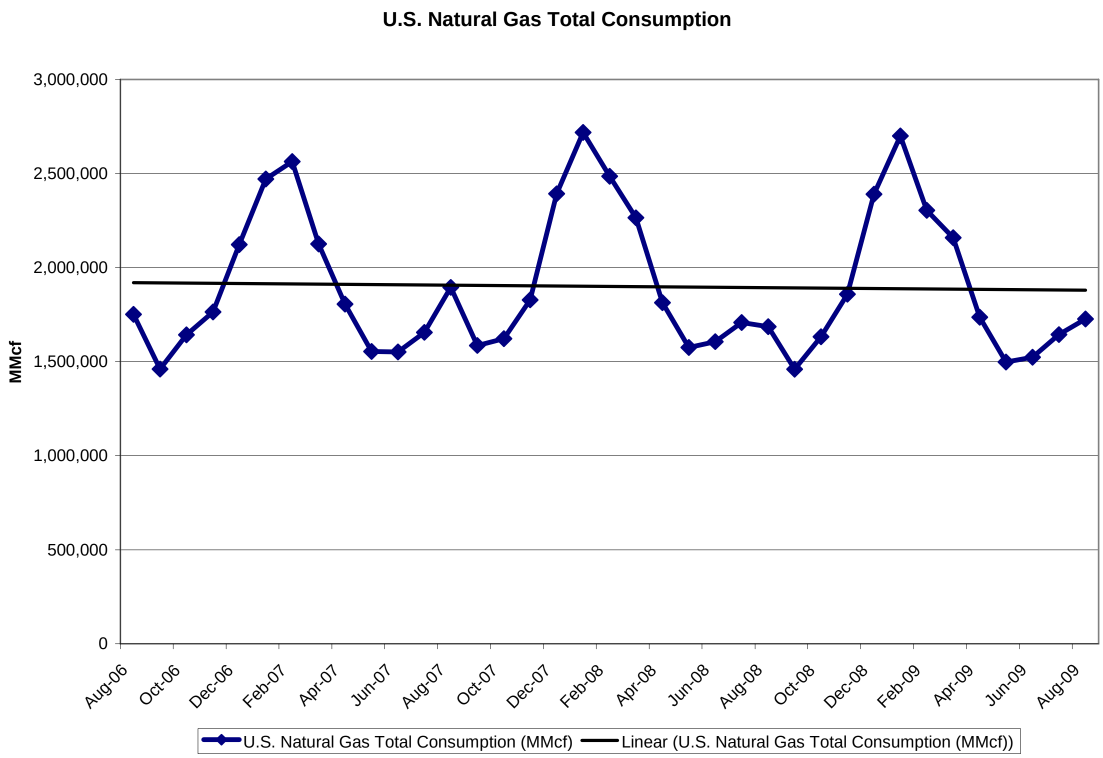
Source: United States Department of Energy, Energy Information Administration, released October 30, 2009.

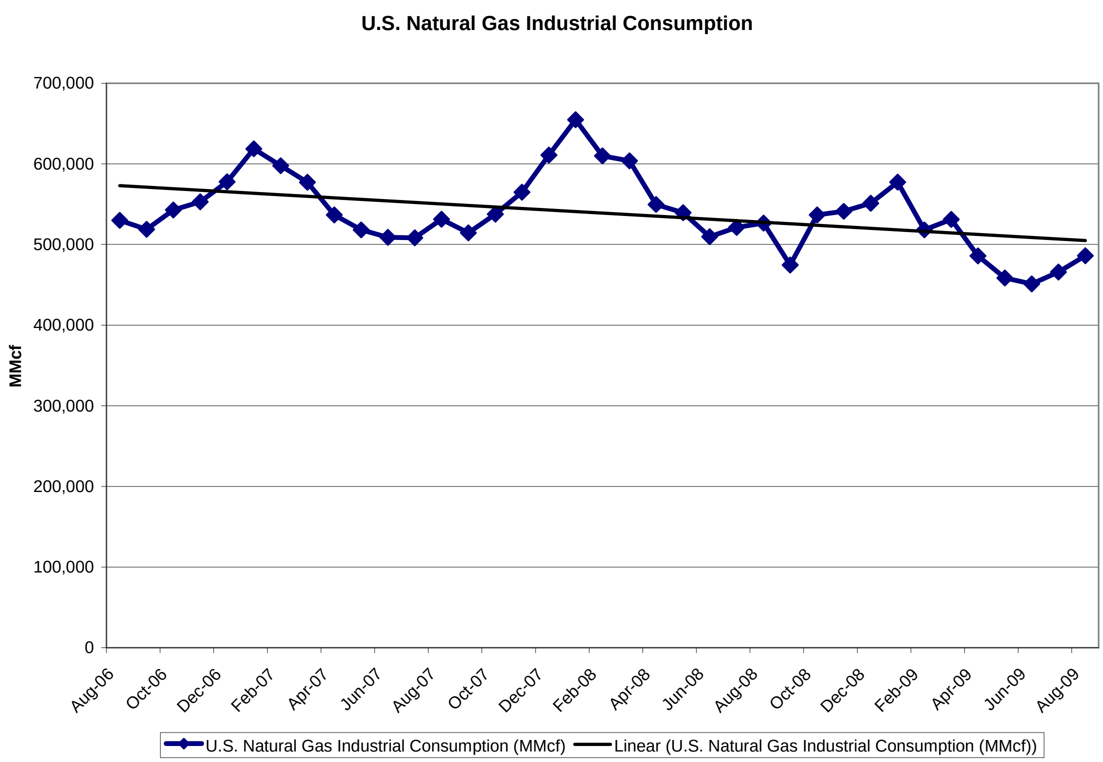
Figure 2 – Natural Gas Rig Count



Source: draft *Resource Program*, Appendix B: Market Uncertainties, Bonneville Power Administration, September 30, 2009, page B-4.

Figure 3 – U.S. Natural Gas Total Consumption and Industrial Consumption





Source: United States Department of Energy, Energy Information Administration, October 30, 2009.

Figure 4 – Natural Gas Storage

Weekly Natural Gas Storage Report

Released: November 5, 2009 at 10:30 A.M. (eastern time) for the Week Ending October 30, 2009.
Next Release: November 13, 2009

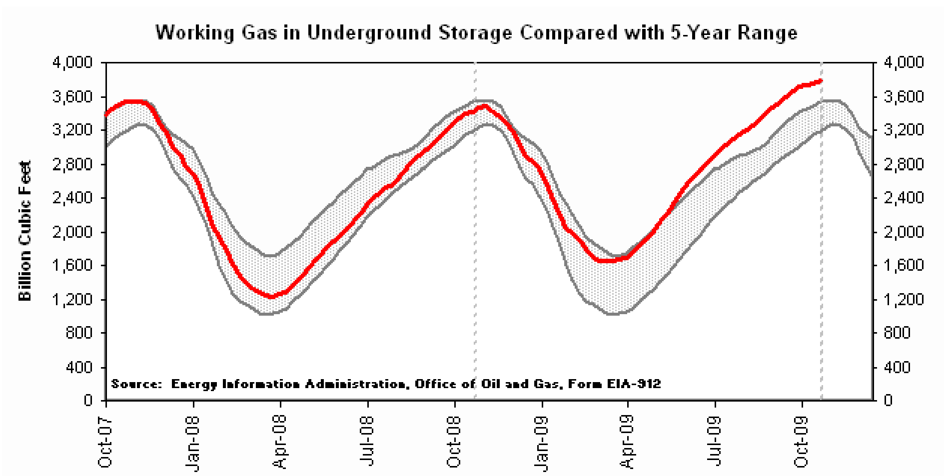
Working Gas in Underground Storage, Lower 48

other formats: Summary TXT CSV

Region	Stocks in billion cubic feet (Bcf)			Historical Comparisons			
	10/30/09	10/23/09	Change	Year Ago (10/30/08)		5-Year (2004-2008) Average	
				Stocks (Bcf)	% Change	Stocks (Bcf)	% Change
East	2,085	2,058	27	2,009	3.8	1,962	6.3
West	514	513	1	461	11.5	450	14.2
Producing	1,189	1,188	1	939	26.6	962	23.6
Total	**3,788**	**3,759**	**29**	**3,409**	**11.1**	**3,374**	**12.3**

Notes and Definitions

Summary
Working gas in storage was 3,788 Bcf as of Friday, October 30, 2009, according to EIA estimates. This represents a net increase of 29 Bcf from the previous week. Stocks were 379 Bcf higher than last year at this time and 414 Bcf above the 5-year average of 3,374 Bcf. In the East Region, stocks were 123 Bcf above the 5-year average following net injections of 27 Bcf. Stocks in the Producing Region were 227 Bcf above the 5-year average of 962 Bcf after a net injection of 1 Bcf. Stocks in the West Region were 64 Bcf above the 5-year average after a net addition of 1 Bcf. At 3,788 Bcf, total working gas is above the 5-year historical range.



Note: The shaded area indicates the range between the historical minimum and maximum values for the weekly series from 2004 through 2008.
Source: Form EIA-912, "Weekly Underground Natural Gas Storage Report." The dashed vertical lines indicate current and year-ago weekly periods.

Source: United States Department of Energy, Energy Information Administration, November 5, 2009.

Attachment D

Five-Month Extension of 20.5 aMW Power Sale Contract No. 09PB-12106 With Port Townsend Paper Company – Administrator's Record of Decision, issued December 24, 2009

Five-Month Extension of 20.5 aMW Power Sale Contract No. 09PB-12106 With Port Townsend Paper Company

Administrator's Record of Decision

On November 13, 2009, Bonneville Power Administration (BPA) executed a power sales contract with Port Townsend Paper Company (Port Townsend) for the sale of up to 20.5 aMW by BPA to Port Townsend for the period November 15, 2009, through December 31, 2010 (Block Contract), and concomitantly issued its rationale for that sale in *Bonneville Power Administration – 20.5 aMW Power Sale to Port Townsend Paper Company for the Period November 15, 2009 Through December 31, 2010 – Administrator's Record of Decision* (November Record).

In the November Record, BPA described certain additional "tangible and intangible benefits to BPA's operations" that it may accrue in connection with the Block Contract in the event that BPA made additional sales to its direct-service industrial (DSI) customers. November Record at 10. However, BPA indicated that it was not accounting for such benefits in its analysis of the Block Contract, inasmuch as the 20.5 aMW sale, in and of itself, was not of sufficient magnitude to significantly impact the financial benefit to BPA. BPA went on to state, however, that

> [T]he accrual of other potential benefits associated with the Block Contract could be significant if the accumulation of additional sales to the DSIs in total were taken into account, resulting in a favorable impact to BPA's forecast of positive net revenues resulting from the Block Contract.

November Record at 11.

On December 21, 2009, BPA executed a power sales contract with Alcoa Inc. (Alcoa), for the sale of up to 320 aMW commencing December 22, 2009 (Alcoa Contract). The Alcoa Contract is described in *Bonneville Power Administration – Power Sale to Alcoa Inc. Commencing December 22, 2009 – Administrator's Record of Decision*, issued December 21, 2009 (Alcoa Record). In the Alcoa Record, BPA described and analyzed in detail the nature and scope of these additional tangible (quantifiable) and intangible (unquantifiable) benefits to BPA associated with the DSI Service. Tangible benefits include avoided transmission costs to BPA's power marketing function that would otherwise be incurred absent the sales to the DSIs, and higher market prices for BPA's surplus sales as a result of DSI load operation (Demand Shift). See November Record at 10; Alcoa Record at 41.

In light of the foregoing, BPA decided to enter into a letter agreement extending the term of the Block Contract with Port Townsend by five months, to May 31, 2011. As explained in this record of decision, BPA believes the five–month extension is justified under the equivalent benefits analysis because of the additional tangible benefits now shown to accrue to BPA for the period from now to the end of the extension.

Benefits to BPA will equal or exceed costs for the extended Block Contract with Port Townsend

BPA forecasts that the revenues it will accrue from the sale to Port Townsend of up to 20 aMW at the Industrial Firm (IP) Power rate will exceed by approximately $54,000 the forecast revenues BPA could otherwise obtain from selling that power into the market through the extended period of the Block Contract with Port Townsend. See Tables 1-6 below. As a consequence, BPA believes service to Port Townsend under the Block Contract is consistent with *Pacific Northwest Generating Cooperative v. BPA*, 580 F.3d 828 (9th Cir. 2009) (*PNGC II)*, that service to a DSI only can be provided if benefits equal or exceed costs.

BPA's projected monthly revenues were determined by multiplying the heavy load hour (HLH) and light load hour (LLH) energy entitlements and demand entitlement by their respective IP rates for each month. BPA calculated revenues under the Block Contract based on the sale of 20 aMW of firm power (not 20.5 MW because power is scheduled in whole megawatts) each hour to Port Townsend under the IP-10 rate schedule beginning November 15, 2009, the commencement of Firm Power deliveries pursuant to the Block Contract, and ending on May 31, 2011. The energy entitlements are the projected amounts of megawatt-hours to be sold by diurnal period each month. The demand entitlement is the projected megawatt amount consumed during the hour of BPA's system peak. BPA's projected monthly revenues were then accumulated and the result is illustrated in Tables 1 and 2:

TABLE 1 - Usage and Rates

Month	Port Townsend Usage			IP-10 Rates		
	Demand (kW)	HLH (MWh)	LLH (MWh)	Demand ($ / kW)	HLH ($ / MWh)	LLH ($ / MWh)
Nov-09	20,000	3,840	3,840	$2.19	$33.33	$29.58
Dec-09	20,000	8,320	6,560	$2.30	$35.24	$31.13
Jan-10	20,000	8,000	6,880	$1.96	$38.46	$32.24
Feb-10	20,000	7,680	5,760	$1.99	$37.72	$31.73
Mar-10	20,000	8,640	6,220	$1.85	$35.94	$30.08
Apr-10	20,000	8,320	6,080	$1.74	$32.23	$26.95
May-10	20,000	8,000	6,880	$1.44	$31.69	$22.29
Jun-10	20,000	8,320	6,080	$1.32	$31.18	$23.29
Jul-10	20,000	8,320	6,560	$1.61	$33.33	$28.66
Aug-10	20,000	8,320	6,560	$1.89	$37.31	$31.40
Sep-10	20,000	8,000	6,400	$1.96	$36.49	$32.26
Oct-10	20,000	8,320	6,560	$2.05	$31.92	$27.01
Nov-10	20,000	8,000	6,420	$2.19	$33.33	$29.58
Dec-10	20,000	8,320	6,560	$2.30	$35.24	$31.13
Jan-11	20,000	8,000	6,880	$1.96	$38.46	$32.24
Feb-11	20,000	7,680	5,760	$1.99	$37.72	$31.73
Mar-11	20,000	8,640	6,220	$1.85	$35.94	$30.08
Apr-11	20,000	8,320	6,080	$1.74	$32.23	$26.95
May-11	20,000	8,000	6,880	$1.44	$31.69	$22.29
Jun-11	20,000	8,320	6,080	$1.32	$31.18	$23.29

TABLE 2 - BPA's Projected Revenue

Month	Revenues by Rate Determinant			Projected IP Revenue	
	Demand ($)	HLH ($)	LLH ($)	Month ($)	Cumulative ($)
Nov-09	$43,800	$127,987	$113,587	$285,374	$285,374
Dec-09	$46,000	$293,197	$204,213	$543,410	$828,784
Jan-10	$39,200	$307,680	$221,811	$568,691	$1,397,475
Feb-10	$39,800	$289,690	$182,765	$512,254	$1,909,730
Mar-10	$37,000	$310,522	$187,098	$534,619	$2,444,349
Apr-10	$34,800	$268,154	$163,856	$466,810	$2,911,158
May-10	$28,800	$253,520	$153,355	$435,675	$3,346,834
Jun-10	$26,400	$259,418	$141,603	$427,421	$3,774,254
Jul-10	$32,200	$277,306	$188,010	$497,515	$4,271,770
Aug-10	$37,800	$310,419	$205,984	$554,203	$4,825,973
Sep-10	$39,200	$291,920	$206,464	$537,584	$5,363,557
Oct-10	$41,000	$265,574	$177,186	$483,760	$5,847,317
Nov-10	$43,800	$266,640	$189,904	$500,344	$6,347,660
Dec-10	$46,000	$293,197	$204,213	$543,410	$6,891,070
Jan-11	$39,200	$307,680	$221,811	$568,691	$7,459,761
Feb-11	$39,800	$289,690	$182,765	$512,254	$7,972,016
Mar-11	$37,000	$310,522	$187,098	$534,619	$8,506,635
Apr-11	$34,800	$268,154	$163,856	$466,810	$8,973,444
May-11	$28,800	$253,520	$153,355	$435,675	$9,409,120
Jun-11	$26,400	$259,418	$141,603	$427,421	$9,836,540

Comparison of net revenues under the Block Contract to forecast revenues that might be obtained by selling an equivalent amount of power on the market.

BPA routinely shapes its inventory to meet the need of its portfolio of contracts and sells its surplus inventory by purchasing and selling in the Pacific Northwest power market as described in BPA's WP-10 rate proceeding.[1] BPA established its forecast of Mid-Columbia trading hub (Mid-C) electricity prices in the WP-10 rate proceeding to value these purchases and sales.[2] For the period covered by the Block Contract BPA has updated its natural gas forecast from that used in BPA's WP-10 rate proceeding to forecast electricity prices to reflect a more contemporary understanding of natural gas fundamentals and to be consistent with the natural gas forecast used in the November Record, the Alcoa Record, and BPA's draft Resource Program released September 30th, 2009.[3]

In the absence of the Block Contract selling 20 aMW of firm power to Port Townsend every hour BPA would have one less firm power requirement sale in its aggregated portfolio load shape to meet; as such BPA would have 20 aMW of surplus energy to sell in the market. As illustrated in Table 3, BPA forecast the revenues it would otherwise obtain from the market using the same forecasting methodology applied in the WP-10 rate proceeding to incorporate our updated forecast of natural gas prices in the development of our electricity price forecast used in this analysis of the five-month extension.[4]

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[1] Refer 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.)

[2] BPA employs 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.)

[3] 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 in 2010 and an increase in 2011. 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, c) record amount of natural gas in storage, d) reduced risk of hurricane impact on supply now that the 2009 hurricane season is nearly over. (See also Short-term Energy Outlooks from the EIA for September and October that have reduced their forecasted Henry Hub Spot Price average for 2010 to $4.78 and $5.02 per Mcf respectively [or $4.64 and $4.87 per MMbtu using EIA's conversion of 1 Mcf = 1.031 MMbtu], *Short-term Energy Outlook*, DOE EIA, September 9, 2009, page 1; *Short-Term Energy and Winter Fuels Outlook*, DOE EIA, October 6, 2009, p. 3.)

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 ($) (HLH + LLH)	Cumulative ($)
Nov-09	$28.75	$26.38	$110,386	$101,285	$211,671	$211,671
Dec-09	$30.61	$27.41	$254,686	$179,826	$434,512	$646,183
Jan-10	$34.13	$29.51	$273,032	$203,019	$476,051	$1,122,233
Feb-10	$34.46	$29.77	$264,654	$171,473	$436,127	$1,558,361
Mar-10	$33.92	$29.16	$293,105	$181,373	$474,478	$2,032,839
Apr-10	$32.95	$28.05	$274,139	$170,563	$444,702	$2,477,541
May-10	$33.93	$24.45	$271,455	$168,220	$439,675	$2,917,217
Jun-10	$34.33	$26.33	$285,619	$160,085	$445,704	$3,362,921
Jul-10	$37.33	$32.18	$310,572	$211,074	$521,646	$3,884,566
Aug-10	$42.48	$35.63	$353,413	$233,703	$587,116	$4,471,682
Sep-10	$42.86	$38.00	$342,871	$243,178	$586,049	$5,057,731
Oct-10	$43.31	$36.85	$360,342	$241,727	$602,070	$5,659,801
Nov-10	$45.36	$40.59	$362,894	$260,574	$623,467	$6,283,268
Dec-10	$48.81	$43.42	$406,097	$284,854	$690,951	$6,974,219
Jan-11	$50.70	$42.13	$405,610	$289,834	$695,445	$7,669,664
Feb-11	$50.78	$42.80	$390,015	$246,519	$636,533	$8,306,197
Mar-11	$49.33	$40.83	$426,216	$253,956	$680,172	$8,986,369
Apr-11	$46.35	$38.79	$385,603	$235,843	$621,446	$9,607,815
May-11	$47.15	$32.65	$377,203	$224,647	$601,849	$10,209,665
Jun-11	$46.50	$33.58	$386,879	$204,196	$591,076	$10,800,740

Net Benefit (IP – Market)

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

[4] 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.

TABLE 4 - BPA's Net Benefit before Adjustment

Month	Net Revenue or (Cost) Month ($)	Cumulative ($)
Nov-09	$73,704	$73,704
Dec-09	$108,898	$182,601
Jan-10	$92,640	$275,242
Feb-10	$76,127	$351,369
Mar-10	$60,141	$411,510
Apr-10	$22,107	$433,617
May-10	($4,000)	$429,617
Jun-10	($18,283)	$411,334
Jul-10	($24,130)	$387,203
Aug-10	($32,913)	$354,290
Sep-10	($48,465)	$305,826
Oct-10	($118,310)	$187,516
Nov-10	($123,124)	$64,392
Dec-10	($147,541)	($83,149)
Jan-11	($126,753)	($209,903)
Feb-11	($124,279)	($334,182)
Mar-11	($145,552)	($479,734)
Apr-11	($154,637)	($634,371)
May-11	($166,174)	($800,545)
Jun-11	($163,655)	($964,200)

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

BPA has identified a number of tangible benefits to BPA that would not be achieved by a market sale of power compared to a sale to Port Townsend under the Block Contract at the IP rate. BPA conducted an economic analysis to determine the value of those benefits and included them in its analysis of the net value of the Block Contract to BPA. 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.

Value of Reserves[5]

The Block Contract requires that Port Townsend make contingency reserves available to BPA, reserves that would not be available from making a typical market sale. BPA takes into account the value to BPA of the reserves Port Townsend is required to make available to BPA under the Block Contract. Sales at the IP rate reflect the value of a right

[5] The value of reserves analysis was described and evaluated in the November Record, and the benefit to BPA from reserves provided by Port Townsend were counted in BPA's analysis in the November Record, that monetary benefit to BPA is shown here again for illustrative purposes, and those benefits are not being double-counted.

for BPA to obtain contingency reserves.[6] 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 analysis above, compares a surplus power sale to a sale of power at the IP rate with reserves. We 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.[7] As illustrated by Table 5a, this was done for every megawatt hour not sold to Port Townsend Paper Company:

TABLE 5a - BPA's Net Benefit Adjustments
Value of Reserves

Month	Month ($)	Cumulative ($)
Nov-09	$6,144	$6,144
Dec-09	$11,904	$18,048
Jan-10	$11,904	$29,952
Feb-10	$10,752	$40,704
Mar-10	$11,888	$52,592
Apr-10	$11,520	$64,112
May-10	$11,904	$76,016
Jun-10	$11,520	$87,536
Jul-10	$11,904	$99,440
Aug-10	$11,904	$111,344
Sep-10	$11,520	$122,864
Oct-10	$11,904	$134,768
Nov-10	$11,536	$146,304
Dec-10	$11,904	$158,208
Jan-11	$11,904	$170,112
Feb-11	$10,752	$180,864
Mar-11	$11,888	$192,752
Apr-11	$11,520	$204,272
May-11	$11,904	$216,176
Jun-11	$11,520	$227,696

Avoided Transmission and Ancillary Services Expenses (additional going forward benefits)

When BPA makes a DSI sale, the DSI customers – including Port Townsend – cover the cost of transmission and ancillary services through their own transmission contracts. Market prices, on the other hand, assume power is delivered by the seller to Mid-C. 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

[6] 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 Port Townsend make such a contingency reserve available to BPA, as defined in section 2.12 and implemented by Exhibit H to the Block Contract.

[7] 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.

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 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 -– including the Block Contract with Port Townsend. The planned transmission and ancillary services expenses to address both the expected expenses and their uncertainty were addressed in the WP-10 rate proceeding.[8] Since PS' overall marketing strategy is to serve all its loads out of inventory and meet any power deficits with short-term purchases, the incremental transmission and ancillary services costs are avoided when BPA makes firm power IP sales to the DSIs.

PS valued these avoided transmission and ancillary services costs using the same methodology used in the WP-10 rate proceeding to establish the total costs and risks associated with PS' 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 DSI, and DSI service of 372 aMW.[9] The average total monthly expense values of the 3,500 games were computed with and without service to the DSI and the differences were taken to determine the avoided PS transmission and ancillary services costs when PS makes these 372 aMW of IP sale(s) to the DSIs. For purposes of this analysis, Port Townsend has been allotted 5.4% 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 in the Block Contract, as depicted in Table 1 above, and as compared to the 372 aMW forecasted for all DSI customers.

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[8] 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.

[9]This number is comprised on 285 aMW for Alcoa, 70 aMW for Columbia Falls Aluminum Company, and 17 aMW for Port Townsend Paper Company.

TABLE 5b - BPA's Net Benefit Adjustments

Avoided Tx and Ancillary Service Costs

Month	Month ($)	Proportional Month ($)	Cumulative ($)
Nov-09	$37,333	$0	$0
Dec-09	$149,138	$1,759	$1,759
Jan-10	$413,785	$18,910	$20,668
Feb-10	$323,044	$14,763	$35,431
Mar-10	$425,880	$19,462	$54,893
Apr-10	$550,208	$25,144	$80,037
May-10	$797,442	$36,442	$116,479
Jun-10	$707,442	$32,329	$148,809
Jul-10	$569,197	$26,012	$174,821
Aug-10	$124,908	$5,708	$180,529
Sep-10	$42,150	$1,926	$182,455
Oct-10	$40,086	$1,832	$184,287
Nov-10	$69,265	$3,165	$187,452
Dec-10	$150,243	$6,866	$194,318
Jan-11	$418,301	$19,116	$213,434
Feb-11	$320,781	$14,659	$228,093
Mar-11	$413,034	$18,875	$246,969
Apr-11	$489,665	$22,377	$269,346
May-11	$764,506	$34,937	$304,283
Jun-11	$669,536	$30,597	$334,880

Demand Shift (additional going forward benefits)

When BPA serves the DSI loads – including Port Townsend – 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 forecasted these increased revenues by reducing loads in the Pacific Northwest by 372 aMW in each month for each of the 3,500 games AURORA simulated for the forecast used in Table 3 above. This lowered the mean price forecast by a 12-month average of $0.29 per MWh and by $0.41 per MWh for fiscal years 2010 and 2011 respectively.[10] The monthly difference resulting from this lower mean price forecast was then multiplied by BPA's monthly surplus energy from the WP-10 rate proceeding to determine the increased revenues available to BPA's surplus sales when BPA makes an IP sale(s) to the DSIs – including the Block Contract with Port Townsend. For the purposes of this analysis, Port Townsend has been allotted 5.4% 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 megawatt amounts in the Block Contract,

[10] AURORA 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.

as depicted in Table 1 above, and as compared to the 372 aMW forecasted for all DSI customers.

TABLE 5c - BPA's Net Benefit Adjustments

Demand Shift			
Month		Proportional	
	Month ($)	Month ($)	Cumulative ($)
Nov-09	$654	$0	$0
Dec-09	$38,176	$450	$450
Jan-10	$143,990	$6,580	$7,030
Feb-10	$182,763	$8,352	$15,382
Mar-10	$274,682	$12,553	$27,935
Apr-10	$428,112	$19,564	$47,499
May-10	$1,332,323	$60,886	$108,385
Jun-10	$893,459	$40,830	$149,215
Jul-10	$515,175	$23,543	$172,758
Aug-10	$36,163	$1,653	$174,411
Sep-10	($24,805)	($1,134)	$173,277
Oct-10	$3,389	$155	$173,432
Nov-10	($32,059)	($1,465)	$171,967
Dec-10	$37,076	$1,694	$173,661
Jan-11	$443,369	$20,262	$193,923
Feb-11	$289,762	$13,242	$207,165
Mar-11	$638,108	$29,161	$236,326
Apr-11	$614,677	$28,090	$264,416
May-11	$1,525,976	$69,735	$334,151
Jun-11	$1,213,864	$55,472	$389,623

Conclusion of Equivalent Benefits Test

The preceding analysis demonstrates how the projected revenues BPA recovers from the nearly 19-month IP sale to Port Townsend (from November 15, 2009 through May 31, 2011) exceed by approximately $54,000 the forecasted revenues that BPA would otherwise obtain from the market. See Table 6 below. BPA's methodology for making this determination is based, to the extent possible, on modeling tools used in BPA's rate case. 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 insure the integrity of the results.

TABLE 6 - BPA's Net Benefit after Adjustments

Month	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 ($)	Cumulative ($)
	BPA's Adjusted Net Revenue or (Cost)					
Nov-09	$73,704	$6,144	$0	$0	$79,848	$79,848
Dec-09	$108,898	$11,904	$1,759	$450	$123,011	$202,858
Jan-10	$92,640	$11,904	$18,910	$6,580	$130,034	$332,893
Feb-10	$76,127	$10,752	$14,763	$8,352	$109,994	$442,886
Mar-10	$60,141	$11,888	$19,462	$12,553	$104,044	$546,930
Apr-10	$22,107	$11,520	$25,144	$19,564	$78,335	$625,266
May-10	($4,000)	$11,904	$36,442	$60,886	$105,232	$730,497
Jun-10	($18,283)	$11,520	$32,329	$40,830	$66,396	$796,894
Jul-10	($24,130)	$11,904	$26,012	$23,543	$37,328	$834,222
Aug-10	($32,913)	$11,904	$5,708	$1,653	($13,648)	$820,574
Sep-10	($48,465)	$11,520	$1,926	($1,134)	($36,152)	$784,422
Oct-10	($118,310)	$11,904	$1,832	$155	($104,419)	$680,003
Nov-10	($123,124)	$11,536	$3,165	($1,465)	($109,888)	$570,115
Dec-10	($147,541)	$11,904	$6,866	$1,694	($127,077)	$443,038
Jan-11	($126,753)	$11,904	$19,116	$20,262	($75,472)	$367,566
Feb-11	($124,279)	$10,752	$14,659	$13,242	($85,626)	$281,940
Mar-11	($145,552)	$11,888	$18,875	$29,161	($85,628)	$196,312
Apr-11	($154,637)	$11,520	$22,377	$28,090	($92,649)	$103,662
May-11	($166,174)	$11,904	$34,937	$69,735	($49,598)	$54,065
Jun-11	($163,655)	$11,520	$30,597	$55,472	($66,066)	($12,001)

Conclusion

For the foregoing reasons, BPA has signed on this date the letter agreement extending the term of the Block Contract with Port Townsend from December 31, 2010, until May 31, 2011.

Issued at Portland, Oregon, this 24th day of December, 2009.

/s/ Allen L Burns
Acting Administrator and Chief Executive Officer

Attachment E

Power Sale to Alcoa Inc. Commencing December 22, 2009 – Administrator's Record of Decision

POWER SALE TO ALCOA INC.
COMMENCING DECEMBER 22, 2009

ADMINISTRATOR'S RECORD OF DECISION

December 21, 2009

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I. INTRODUCTION

On December 14, 2009, BPA made a contingent offer of a block power sales contract to Alcoa, Inc. ("Alcoa") commencing December 22, 2009, (the "Block Contract") pending the Administrator's final decision regarding whether to sign the Block Contract. Under the Block Contract, BPA proposed to sell to Alcoa up to 320 aMW of power over approximately 17 months on a firm basis, and for an additional 5 years if certain specified conditions are met. Service will be provided at the Industrial Firm (IP) power rate. BPA made the draft contract available for public review on October 30, 2009. This record of decision addresses the comments received, and provides 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") 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*"). Prior to issuance of those opinions, BPA provided service to Alcoa by means of a monetized sale of surplus power pursuant to section 5(f) of the Pacific Northwest Electric Power Planning and Conservation Act ("Northwest Power Act" or "NPA"), 16 U.S.C. § 839c(f). In response to the Court's opinions, BPA is no longer monetizing the sale, nor is BPA selling surplus power to Alcoa. Instead, pursuant to the new power sales contract that is the subject of this record of decision, BPA is making a sale of physically delivered industrial firm power pursuant to authority provided under section 5(d) of the NPA, which authorizes the Administrator "to sell in accordance with this subsection electric power to existing direct service industrial customers." 16 U.S.C. § 839c(d)(a)(A).

The sale is priced at the Industrial Firm power ("IP") rate, described at section 7(c) of the Northwest Power Act, which is the applicable rate for sales of non-surplus firm power to BPA's direct service industrial ("DSI") customers. 16 U.S.C § 839e(c). The Court found that the IP rate is the statutorily required rate for such sales. See *PNGC I,* 580 F.3d at 812.

The Court required in *PNGC II* that any offer of power to a DSI must be "consistent with sound business principles." See *PNGC II* at 842.. More particularly, careful review of the Court's opinion in *PNGC II* has led BPA to conclude that, in order to offer a sale of power to a DSI, BPA must conclude based on evidence in the record that the proposed transaction will result in benefits that equal or exceed the costs to BPA of the transaction. In response, BPA has developed an "Equivalent Benefits Test". BPA has determined with respect to the power sales contract with Alcoa that, for a period approximately equal to the first seventeen months of the contract term, service can be provided in a manner that meets the test.

BPA is obligated to adhere to the Court's opinions. However, as discussed later in this Record of Decision, BPA does not believe that imposition of an equal or net benefits standard, as embodied by the Equivalent Benefits Test, is consistent with BPA's enabling statutes. Such a standard misreads explicit statutory language, and is fundamentally inconsistent with BPA's dual roles as a business enterprise and a governmental entity. In those roles, the Administrator has traditionally had, and should continue to have, flexibility to weigh the financial benefits of any given transaction or final action against other considerations related to BPA's statutory responsibilities. BPA should not be confined, as the Court seems to have done, to consideration of only the "bottom line."

II. POLICY DISCUSSION

The Block Contract will supply firm power to Alcoa's Intalco Works ("Intalco Plant"), a long-standing directly-served aluminum smelter in Ferndale, Washington. The contract provides for the sale of firm power by BPA to Alcoa, at the applicable industrial firm power (IP) rate, during an initial period and potentially a subsequent 5-year period.

While BPA's enabling statutes contain a great number of sometimes competing policies, one in particular warrants attention here: the purpose of the Northwest Power Act to "to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply . . ." 16 U.S.C. § 839(2). As the language makes clear, the purpose is not directed specifically at preference customers, or any other single customer class or interest group, but to assure "the Pacific Northwest" of an "adequate, efficient, economical, and reliable power supply." The Administrator does not act with a view to operating as a profit-making enterprise. In broadest terms, BPA's statutorily defined mission is to dispose of low-cost federal power at cost. Many of BPA's statutory responsibilities evince social policies that might be viewed as inimical to acting purely like a "business." In the context of insuring an adequate, efficient, economical and reliable power supply, it is certainly reasonable for BPA to consider the impact of its actions on the continued viability of its customer base, including the DSIs.

BPA believes the sale:

- provides a balanced approach to supplying Federal power to Alcoa,
- limits BPA's financial exposure, and
- conforms with *PNGC I* and *PNGC II*.

BPA's approach is balanced. BPA's current approach to DSI service recognizes that DSIs have historically been an integral part of the Federal system virtually since its inception. Because DSIs have been directly served and are statutorily defined as "direct service industrial customers," DSIs do not receive retail electricity service from any of BPA's retail distribution utility customers, or from any of the regional investor-owned utilities. DSIs have therefore relied on BPA or the wholesale power market to meet their operational needs. In the case of aluminum smelter load, power requirements account for one-third of total operating costs, which makes it essential for such operations to have a dependable and low-cost power provider, so that a solid basis exists for long term planning and marketing. Likewise, the sale to Alcoa will assure BPA of a fixed load and a steady revenue stream to help BPA meet its repayment obligations to the United States Treasury. *See, e.g.,* Northwest Power Act, 16 U.S.C. 839e(a)(1) (rates must be established and revised to recover costs, including "the amortization of the Federal investment in the Federal Columbia River Power System.")

BPA's financial exposure is limited. BPA has determined that during the so-called "Initial Period" (comprising a sale of power for approximately 17-months from December 22, 2009, through May 26, 2011 under the Block Contract) application of the Equivalent Benefits Test shows the forecast benefits to BPA during that period exceed the forecast cost. A so-called "Second Period" of power sales could be available under the Block Contract, but only if service can be provided in a manner that is consistent with an opinion or ruling by the Court that holds, or can reasonably be interpreted to mean, that the Equivalent Benefits Test does not apply to BPA sales. In that case, service will still be conditioned upon and subject to cost caps that will limit BPA's financial risk, and mitigate rate impacts on other customers. All sales will also be made at the applicable IP rate, which insures that BPA will obtain revenues in excess of revenues obtained through sales at the PF rate, while avoiding the variability and volatility associated with making market sales. Additionally, BPA can impose assurance payment provisions for power sold, and BPA will retain any gains from reselling power not taken while Alcoa retains a take-or-pay obligation in most situations. Taken together, these risk provisions support BPA's ability to meet its Treasury payment obligations and mitigate rate impacts on BPA's other power customers.

In its comments, the Industrial Consumers of Northwest Utilities ("ICNU") object to BPA's approach on the basis that "BPA's own analysis shows that the Block Contract is only profitable for the first eight months and BPA loses money on the contract in each of the next eleven months." ICNU at 3.[1] PPC states that it "opposes any service to the Direct Service Industries (DSIs) that comes at the expense of preference customers" and that "BPA has once again failed to demonstrate that sound business reasons underlie its proposal." PPC at 1. PPC argues that *PNGC II* requires that the "agency may only engage in a transaction with the DSIs if it is expected to result in a benefit to the federal system." PPC at 2. BPA does not interpret *PNGC II*, as ICNU does, to require that the Block Contract be profitable for each month of the entire term of the Initial Period, but instead reads the opinion to allow that, in the aggregate, the Block Contract provide benefits that equal or exceed the cost over its term. If BPA sold an equivalent amount of power on the market, at a fixed price over a similar period of time, there would be no

[1] Comment cites are to comments filed regarding the proposed Block Contract on November 9, 2009, unless otherwise noted.

guarantee that the fixed price would meet or exceed the prevailing market price in each and every month of the period. In fact, it would be likely that the fixed price would be below market during some periods; thus, in that situation, BPA could be accused of not maximizing its revenues. Yet, such an agreement could, in fact be justified on the grounds that it mitigated the risk of fluctuating prices over the term of the contract and therefore supported BPA's obligations to recover its costs consistent with sound business principles. Similarly, the Block Contract with Alcoa, as shown in more detail below, provides mitigation of market risk and provides BPA with a valuable fixed revenue stream in a manner that has no adverse rate impacts on other customers during the Initial Period and limited impacts in the Second Period, if any.

It is not clear what PPC means by a "benefit to the federal system." BPA interprets the Court's discussion of a proposed transaction being "consistent with sound business principles" to mean that benefits to BPA of the transaction must equal or exceed costs. As the Court clearly recognized, benefits can take many forms, whether quantifiable in financial terms or not. If service to a DSI promotes one or more of BPA's statutory missions, such a benefit might be reducible to a monetary value, or it might not. Other benefits might not be reducible to a dollar amount. Or, benefits might benefit a non-DSI customer group or public interest but not another, again making it difficult to assess the value of the benefit in relation to the detriment to another group. Also, there could be potential future benefits that might turn out to be of significant value or minimal value depending on how circumstances developed. Nonetheless, even a benefit not readily reducible to a dollar amount is real and should be accounted for, if not in strict economic terms, then in some fashion. In this particular instance, BPA did not attempt to account for such benefits because the tangible benefits that can be measured in economic terms were sufficient to support the Initial Period of approximately seventeen months.

Moreover, trying to determine if something is a "benefit to the federal system" is a questionable proposition because the term is so vague and amorphous. Without additional definition of the term, it does not provide a meaningful standard. On the one hand, it can be inferred from the comments from BPA's public body and cooperative utility customers that they interpret it to mean a benefit to them through lower power rates, *i.e.*, BPA ought to sell the power as surplus into the market (or at least reap market prices if sold to DSI customers) so resulting surplus revenue can be credited to the PF rate. On the other hand, a benefit could be almost anything that promotes any of BPA's statutory mandates, whether marketing low-cost federal power to promote widespread use, selling power to supply the needs of all of BPA's regional power customers, advancing fish and wildlife mitigation, insuring a reliable power system, advancing the purposes of the Northwest Power Act, or other BPA mandates.

The Block Contract is consistent with law. *PNGC I* and *PNGC II* upheld BPA's discretion to serve the DSIs at the IP rate. *PNGC I*, 580 F.3d, 792, 807 (Section 5(d) of the NPA "authorizes but does not obligate the agency to sell power to the DSIs") and *PNGC II*, 580 F.3d 828, 835 (BPA "authorized to sell power to the DSIs at the IP rate") However, BPA believes there is still some uncertainty in the Court's opinions with respect to what the law requires when assessing whether a DSI sale is consistent with sound business principles. BPA has taken a cautious approach, applying the Equivalent Benefits Test to the Initial Period. As noted above, pursuant to application of that test, the Initial Period of service under the Block Contract will provide BPA with benefits that exceed BPA's cost. In taking this approach, BPA has deferred consideration of other aspects of the Court's rulings, which suggest that decisions regarding DSI service can include consideration of factors that cannot readily be reduced to a monetary amount. For example, in *PNGC II*, the court pointed to "non-financial" benefits that might be provided. 580 F.3d at 835. As noted above, BPA has not developed an analytical framework for consideration of non-financial benefits. BPA will, however, continue to consider how such benefits may be applied consistent with the Court's opinions. This could be particularly important when BPA considers service for the contingent Second Period of the Block Contract, which encompasses five years of service following the Initial Period. BPA's approach is entirely appropriate at this time, in that it provides a significant period of service based on its view of the Court's opinions, while leaving room for additional flexibility at a later date in the event that the Court determines that an equivalent benefits test need not apply to sales under this contract and further clarifies what it means for BPA to enter into a transaction consistent with sound business principles.

III. BACKGROUND

a. Original Contract

The Block Contract represents BPA's attempt to structure a power sales contract for service to Alcoa that responds to the Court's opinions in *PNGC I* and *PNGC II*, issued in connection with petitions for review challenging the five-year power sales agreement (the subject of the *PNGC I* challenge), and an amendment thereto (the subject of the *PNGC II* challenge) by and between BPA, the Public Utility District No. 1 of Whatcom County, Washington, and Alcoa, whereby BPA agreed to sell to Whatcom, and Whatcom agreed to sell to Alcoa, 320 aMW for the period October 1, 2006, through September 30, 2011 ("Original Contract").

The Original Contract was structured so that BPA, at its option, could monetize the value of the contract pursuant to a formula contained in the contract, and make financial payments to Alcoa in lieu of physically delivering power. By monetizing the contract and capping the amount of benefits it would pay to Alcoa, BPA was able to mitigate any purchase power risk it may have in the event it needed to make market purchases in order to serve Alcoa's load, and thereby meet its twin goals of allocating some benefits of the federal power system to its long-time customer Alcoa, but at a known and capped cost. Payments were calculated and paid (up to the cap) based on the difference between BPA's lowest-cost base rate available to its public preference customers (the PF rate), and market prices. Alcoa therefore was responsible for procuring its own power supply in the market, using the payments by BPA to lower its actual power purchase cost. In its opinion issued December 17, 2008, the Court in *PNGC I* held, among other things, the monetization formula, and the payments made pursuant that formula, invalid inasmuch as it was based on a rate that was below both the IP rate and market prices. 580 F.3d at 820. Prior to the Court's opinion, pursuant to certain reallocation provisions in the Original Contract, BPA agreed to provide Alcoa an additional 70 aMW in benefits, raising Alcoa's demand entitlement to 390 aMW for the period October 1, 2007 through September 30, 2011.

b. Amendment to the Original Contract

In response to *PNGC I*, BPA and Alcoa entered into a ten -month amendment to the Original Contract, which was intended to conform the Original Contract to the Court's opinion, allowing BPA to continue service to Alcoa under an IP equivalent rate, until such time as the parties could fashion a new contract to replace the Original Contract. Pursuant to the amendment, BPA continued to monetize the value of the transaction in lieu of physically delivering power to Alcoa, but calculated these payments (again limited by the caps established in the Original Contract) based on the difference between the IP rate (rather than the lower PF rate) and BPA's forecast of market prices. BPA believed this approach was consistent with the Court's central holding in *PNGC I* that service to BPA's direct service industrial customers must be based on the IP rate. 580 F.3d at 812 ("BPA, when entering into contracts for the sale of firm power to a DSI, must initially offer the IP rate") Petitions for review challenging the amendment were filed, and in *PNGC II* dated August 28, 2009, the Court held, among other things, that BPA had failed to demonstrate how entering into the amendment was consistent with sound business principles. 580 F.3d at 842.

c. December Draft Contract

In connection with its goal of negotiating new long-term contracts with all its public, investor-owned utility, and DSI customers, and prior to the Court's opinion in *PNGC I* in October 2008, BPA commenced a public process (including workshops and public review/ comment) to fashion a contract for Alcoa to be effective upon expiration of the Original Contract in September 2011. BPA proposed a set of principles that, if adopted, could have led to a power sales contract in which BPA would have provided Alcoa 240 aMW of power (150 aMW less than the maximum amount available to Alcoa under the Original Contract) for a period of ten years at the IP rate, beginning in 2012, and 160 aMW (or 230 aMW less than under the Original Contract) for an additional seven years in the event BPA determined it could provide such service within predefined price caps.

BPA submitted a proposed contract for public review and comment in December 2008 (December Draft Contract). Pursuant to the December Draft Contract, BPA's obligation to serve Alcoa was contingent on BPA's ability to purchase market power within predefined price caps, but BPA agreed to pay certain of Alcoa's shutdown costs in the eventuality it could not purchase power at or below the caps, which averaged $65 million per year. A later contract draft would have obligated BPA to provide Alcoa up to 240 aMW of power, beginning in 2012 for 17 years, within a predefined 240 aMW price cap starting at $72 per MWh for FY 2012 through FY 2016 and rising to $90 per MWh in FY 2021.

However, as time passed, aluminum prices continued to plummet, as they had been for several months prior, and Alcoa was forced to reassess whether it could continue operations and perform its obligations under the proposed contract with BPA, given the dire aluminum market conditions. On January 22, 2009, BPA and Alcoa issued a joint letter to the region indicating that Alcoa had concluded it could not sign the contract. BPA posted the contract on its website on January 23.

d. *PNGC I*

In the meantime, on December 17, 2008, the Ninth Circuit issued *PNGC I* responding to petitions challenging the legality of the Original Contract. In *PNGC I*, the Court conducted an extensive analysis of BPA's statutory authority to serve the DSIs and the appropriate rate under which to provide such service. The Court resolved some issues in a manner adverse to BPA and some in BPA's favor, and on the basis of such rulings, the Court granted in part, denied in part, and dismissed in part the petitions for review. Most notably, the Court found that:

- BPA has the statutory authority, but not the obligation, to sell power to the DSIs (580 F.3d at 807);
- BPA, when entering into contracts for the sale of firm power to a DSI, must initially offer power at the Industrial Firm Power ("IP") rate prior to offering power at any other rate (*id*. at 817);
- BPA erred in the Agreements under review in *PNGC I* because BPA provided financial benefits to the DSIs "at a rate that was below both the market rate *and* the statutorily authorized IP rate . . . " (*id*. at 823) (emphasis in original);
- the challenged Agreements were not void: "[w]e do not hold that the contracts are void . . . Instead, we *affirm* the authority of BPA to sell physical power to the DSIs, § 839c(d), at a valid rate." (*id.* at 827) (emphasis in original); and
- BPA may lawfully provide monetary benefits to a DSI rather than provide a physical supply of power as long as BPA does so under appropriate circumstances consistent with BPA's specific statutory obligations (*id.* at 821, fn 35).

e. August Draft Contract

In a May 29, 2009 letter to the region, BPA convened a new public process to consider whether the unsigned December Draft Contract "should be changed, and what changes are needed for the term of future contracts".[2] A workshop was held on June 8, 2009. Alcoa also made a presentation during the workshop that detailed their operating costs and how the Intalco Plant compared to other U.S. aluminum smelters. The materials indicated that Alcoa's Intalco Plant was cost efficient and energy efficient but had suffered from relatively high power costs. In summary, Alcoa stated that a "mid to long-

[2] Letter to region, Bonneville Power Administration, May 29, 2009 at 1.

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".[3]

In a July 17, 2009 letter to the region, BPA proposed term sheets for a firm power sale at the IP rate that would be sufficient to meet a portion of the smelter's load for up to seven years. BPA also provided its "Summary of BPA's Use of the Regional Economic Study to Contemplate the Service Concept" which is BPA's update to the results of the "2006 Regional Employment and Economic Study". BPA's summary demonstrated there would be a small net gain in jobs from offering the new service constructs to the DSIs compared to the proposal that was under consideration earlier in January 2009. BPA accepted public comments on the proposed term sheets through August 3, 2009, and received 221 comments.

In an August 19, 2009, letter to the region, BPA proposed a seven year (October 1, 2009, through Sept. 30, 2016) block power sales contract ("August Draft Contract") of up to 320 average megawatts at the IP rate sufficient to meet a portion of Alcoa's load at its Intalco Plant. As an attachment to the August 19th letter, BPA provided it's "Summary of Changes BPA has Made in the Draft Contract in Response to the Public Comment Process on the Alcoa Term Sheet." The contract was contingent on BPA determining it could provide service within the cost caps established therein.

While the August Draft Contract provided more flexibility than the earlier unsigned draft contract, BPA believed that the changes above, taken together, better met the objectives outlined for DSI service than the term sheet. The August Draft provided a balanced approach, limited BPA's financial exposure, and appeared to be legally sustainable. However, the issuance of a second Ninth Circuit opinion, *PNGC II*, altered BPA's assessment of its objectives. In particular, the August Draft Contract no longer appeared to be legally sustainable.

f. *PNGC II*

On August 28, 2009, the Ninth Circuit issued its opinion in the case challenging the Alcoa amendment in *PNGC II*. The opinion raised additional issues regarding service to DSI customers, and BPA concluded it could not reach a final decision whether to offer the August Draft Contract prior to October 1, 2009. BPA determined it needed additional time to evaluate *PNGC II*, and make a determination, in light of that opinion, whether offering a multi-year contract to the DSIs, including Alcoa, would be consistent with "sound business principles" as BPA believes that standard was described in *PNGC II*.

While BPA's reading of *PNGC II* is addressed at length in Part VI below, it is pertinent to restate here that BPA interprets *PNGC II* as requiring that if the Administrator exercises his discretion to serve a DSI customer, the decision to serve must be consistent with "sound business principles." As described by the Court, 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

[3] See Public workshop presentation, Alcoa, June 8, 2009.

load during the period of service. If they do not, then the Administrator must demonstrate that there is a reasonable prospect that the short-term net cost of providing DSI service will be offset by positive net benefits of future DSI service. BPA has responded to the *PNGC II* requirement by applying, at the outset, the Equivalent Benefits Test, a test that comports with the Court's ruling.

In the meantime, BPA concluded that *PNGC II* did not support the agency making the remaining payments to Alcoa under the Original Contract, as amended, which (as noted earlier) was being implemented by monetizing the power sale, *i.e.*, providing the financial equivalent of the costs that BPA believed it would have otherwise incurred through a physical sale of Federal power at the IP rate. Therefore, in its September 17, 2009, letter to the region, BPA announced it would not make the scheduled payments for August and September. These payments would have been made September 11 and October 13, 2009.[4] Taken together, the payments to Alcoa would have amounted to approximately $6 million.

g. November Draft Contract

BPA endeavored to address *PNGC II* consistent with its objectives for DSI service. This led to BPA's October 17, 2009 letter to the region proposing revisions to the August Draft Contract (the "November Draft Contract") to comport with "sound business principles," as that standard was described in *PNGC II*, the key feature being the incorporation of an the Equivalent Benefits Test that requires that benefits that are forecast to accrue to BPA as a result of providing firm power service to Alcoa equal or exceed the forecast cost of providing such service at the Industrial Firm Power (IP) rate.[5]

BPA's application of the test showed it would be able to offer Alcoa a contract with an Initial Period of 19 months on a non-contingent basis, during a period commencing on December 1, 2009 and ending on June 30, 2011. The November Draft Contract also provides for a Second Period after the Initial Period, but this follow-on period is contingent on an opinion or ruling by the Court that holds, or can be reasonably interpreted to mean, that the Equivalent Benefits Test does not apply to BPA sales, BPA's determination that the Second Period sale would satisfy the Court's rulings, and BPA's determination that the Second Period cost caps can be met. In most other material respects, the November Draft Contract reflects the terms of the August Draft Contract.

In the meantime, Alcoa continued to operate in October and November by providing for its own power needs, and will continue to do so through December 21, 2009. BPA indicated in mid-November that it would need additional time beyond the proposed December 1, 2009, start date to allow for its evaluation of the comments filed by parties with respect to modifications made in the November Draft Contract (referred to herein as the "Block Contract" as described immediately below), and to draft this record of decision detailing its final decisions with respect to that contract.

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[4] Letter to the region, Bonneville Power Administration, September 17, 2009.
[5] Letter to the region, Bonneville Power administration, October 17, 2009.

IV. BLOCK CONTRACT

a. Summary of Block Contract

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

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 December 22, 2009, through May 26, 2011, and the Second Period encompassing the five-year period following expiration of the Initial Period. However, the Block Contract provides that the Initial Period may be extended (subject to certain conditions precedent) for a minimum of three months and a maximum of one year (the Extended Initial Period). Therefore, the Initial Period, as extended, could have a maximum term of 29 months, through May 26, 2012. See Block Contract, section 5.

As of the effective date, BPA would have made available 285 aMW to Alcoa, but Alcoa has requested that BPA increase such amount to 320 aMW, pursuant to applicable contract provisions. See Block Contract section 5.2. As described more fully below, BPA has concluded that it will achieve Equivalent Benefits from the sale of 320 aMW to Alcoa during the Initial Period, and has granted Alcoa's request. 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 section 5.1.1.

The Second Period will commence, if at all, as specified in section 6 of the Block Contract, which provides for a Second Period only if following execution of this Block Contract, (i) the Ninth Circuit holds that the Equivalent Benefits standard does not apply to sales under the Block Contract, (ii) BPA determines that selling 320 aMW to Alcoa under the Block Contract during a Second Period would be consistent with the Court's rulings with respect to service to the DSIs, and (iii) BPA determines that the cost of selling 320 aMW to Alcoa under the Block Contract during a Second Period would not exceed the cost caps specified in Exhibit B of the Block Contract.

The period between the date of the foregoing Ninth Circuit holding and BPA's subsequent decisions regarding continued service to Alcoa under the Block Contract is referred to in the Block Contract as the "Transition Period", and may have a term of up to one year. See Block Contract section 6.1. The Transition Period will, depending on the disposition of any petitions for review challenging the Block Contract by the Court, fall completely or only partially within the Initial Period or any Extended Initial Period; but any Second Period will commence no earlier than the expiration of the Initial Period or Extended Initial Period. To the extent the Transition Period extends beyond the term of the Initial or Extended Initial Period, then as specified in section 6.1.2, BPA may serve Alcoa under the Block Contract pending its determinations regarding service to Alcoa in a Second Period. In the event there is no Second Period, then the Block Contract will terminate as specified in section 5.3 or section 6.2.

The Block Contract contains cost caps. See Block Contract section 7. The level of the cost caps, and the manner in which BPA will evaluate whether the cost of service to Alcoa is equal to or less than the applicable cost caps, are specified in Exhibit B of the Block Contract. The cost caps will apply only to BPA's evaluation of whether it will provide service under the Block Contract during a Second Period. By contrast, service to Alcoa under the Block Contract during the Initial Period (as well as any increase in the level of service from 285 aMW to 320 aMW, or any extension of the term of the Initial Period) is contingent on BPA determining that it will achieve Equivalent Benefits from such service. Therefore, the cost caps are unnecessary and would provide no meaningful additional risk mitigation to BPA during the Initial Period or Extended Initial Period.

While Alcoa's obligation under the Block Contract is take-or-pay, it may curtail its load pursuant to the terms and conditions specified in section 9 of the Block Contract. During such periods of curtailment Alcoa's take-or-pay obligation is excused. During such periods of allowable curtailment, Alcoa is not liable for any losses BPA may incur in remarketing such curtailed power, nor is it entitled to the benefits BPA is more likely to receive. Several parties in comments questioned why Alcoa is not obligated to pay BPA damages in the event that BPA accrues less revenues from remarketing curtailed power than it would have received from selling such power to Alcoa under the Block Contract. See e.g., WPAG at 6; Snohomish at 5. The rationale for excusing Alcoa's take-or-pay obligation, and not requiring Alcoa to pay BPA damages, if any, associated with a curtailment under the Block Contract is discussed more fully elsewhere in this record of decision.

Alcoa is obligated, at BPA's request, to arrange for BPA to be provided with a $30 million standby letter of credit, issued in a form and by a bank acceptable to BPA, and to have issued, at BPA's request, replacement standby letters equal to the value of 103 days of power service, calculated using the highest monthly average IP rate, so that a letter of credit is in place for the term of the Block Contract. See Block Contract section 21.8. BPA may seek additional performance assurance from Alcoa to the extent Alcoa's financial responsibility or performance viability become unsatisfactory to BPA. See Block Contract section 21.8.3.

In addition to the standard termination for default provisions, each party has the right to terminate the Block Contract under certain additional circumstances. BPA's additional termination rights primarily relate to cases where it has made a determination that it cannot serve Alcoa consistent with the Court's rulings or opinions, or at a cost that is at or below the cost caps. See Block Contract section 6.2. For its part, Alcoa may terminate the Block Contract at any time during the Initial, Extended Initial, or Transition Periods, on six months notice, and during any Second Period on 12 months notice. See Block Contract sections 22.1.1.1 and 22.1.1.2. In each case, Alcoa retains some (in the case of termination during the Initial, Extended Initial, of Transition Periods) or all (in the case of a termination during a Second Period) of its take-or-pay obligation.

Alcoa may terminate at any time, and on one day written notice, in the event BPA has made a determination pursuant to section 6.2 that it cannot serve Alcoa during a Second Period. See Block Contract section 22.1.2. Alcoa also may terminate in the event it has been billed directly, and paid to BPA, in excess of $2 million for certain environmental or regulatory costs. See Block Contract section 22.1.4. In each of the foregoing terminations, Alcoa has agreed (except in the case of a termination following a determination by BPA under section 6.2) that it will not restart the Intalco Plant until after the time when a Second Period would have otherwise ended. See Block Contract section 22.1.5.

Alcoa has made certain covenants, including agreeing not to challenge the validity of the Block Contract, any determinations by BPA regarding Equivalent Benefits, or any BPA determination under Exhibit B. See Block Contract section 25.1. In addition, Alcoa has agreed not to request any surplus power from BPA during the term of the Block Contract, and not to challenge any proposed or actual sale of surplus power by BPA, or to challenge any rate adopted by BPA for the sale of surplus power. See Block Contract section 25.2. Finally, Alcoa agreed that it will waive any claims it may have under Contract No. 06PB-11744, as amended, in the event BPA determines on remand in *PNGC I* and *PNGC II* that no payments are owing to or from either party under such contract, but that such waiver will be of no force or effect in the event that the Ninth Circuit grants a petition for review challenging BPA's determination.

b. Contract Demand

As noted, pursuant to the Block Contract, BPA has agreed (subject to certain conditions precedent) to make available to Alcoa, and Alcoa has agreed to purchase from BPA (on a take-or-pay basis) up to 320 aMW for a period of up to approximately seven years, at the IP rate.

Alcoa is currently operating at 285 aMW with power purchased from the wholesale power market. BPA has previously offered Alcoa service benefit levels equal to or in excess of that needed to operate two of the three potlines at the Intalco Plant, or approximately 320 aMW.[6] Alcoa has also indicated that 320 aMW is sufficient to provide a reasonable chance for continued operation of the Intalco Plant, preserving jobs that are dependent upon Alcoa operating that facility.[7]

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[6] The 320 aMW amount is equal to the service benefit level established in the BPA/Alcoa contract for the FY 2007 through FY 2011 period. The amount provided in the BPA/Alcoa contract for the FY 2002 through FY 2006 period was 718 aMW. Historically, BPA has contracted with Alcoa for all of its delivery points under one contract. As such, the 718 aMW refers to the contract demand in the Subscription contract for the FY 2002 through FY 2006 period covering the following points of delivery: Ferndale, Longview, Troutdale, and potentially Wenatchee.

[7] See letter re *7-year power sale agreement*, Alcoa, Inc., submitted to BPA September 9, 2009, in public comment on the Draft Contract, at 1: "While Alcoa would much prefer to receive a sufficient amount of power to serve the entire electric power load that BPA has traditionally served, we believe that the offer of 320 average megawatts of power (enough to serve two of three of Alcoa's potlines) will permit the Intalco

Purchases for the Intalco Plant from BPA have been greater than the 320 aMW in the past. The historic contract demand for the Alcoa Intalco plant is 468 MW, as provided by section 5(d) of the NPA, as implemented and established in the Intalco Aluminum Corporation's 1981 power sales contract. Section 5(d)(1)(B) of the NPA directed BPA to offer each DSI an initial long-term contract in an amount, referred to generally as its "contract demand," equivalent to the amount of power each DSI was entitled to under its then existing BPA power sales contract. For the Intalco Aluminum Corporation, this amount was 445.6 MW. The resulting 1981 DSI power sales contracts provided that a company's contract demand could be increased for certain efficiency improvements and modifications to plant equipment, including the addition of certain environmental protection equipment. These increases were referred to in the 1981 DSI contracts as "technological allowances," and in 1987 the Intalco Aluminum Corporation applied to BPA for such an increase. BPA approved the request in September 1987, thereby increasing the Intalco Aluminum Corporation's contract demand (*i.e.*, the maximum amount of IP power BPA may legally provide to Alcoa) to 468 MW. See Attachment A. The Intalco Aluminum Corporation was later acquired by Alcoa Inc.

Under the BPA/Whatcom/Alcoa Contract, Alcoa's service benefit was initially 320 aMW for the period October 1, 2006, through September 30, 2011. Subsequently, pursuant to certain provisions of that contract, and upon expiration of another aluminum smelter's right to service benefits, BPA agreed to sell and Alcoa accepted the purchase of an additional 70 aMW of service benefits, raising their demand entitlement to 390 aMW for the period October 1, 2007 through September 30, 2011. This changed the allocation of service benefits amongst the DSIs, but did not increase the collective load of the DSIs.

In fact, DSI loads served by BPA, in total, continue to decline because Golden Northwest Aluminum has not been operating and does not qualify for a contract in the Regional Dialogue period, Alcoa's maximum demand in the Block Contract is 320 aMW and an equivalent maximum demand for CFAC is 140 aMW – also equivalent to two pot lines.[8] BPA determined that it could offer Alcoa an opportunity to ramp up to 320 aMW because Alcoa agreed to a cost cap for the Second Period that was actually lower than the one proposed in the December Contract Draft. For the Initial Period, BPA will still achieve equal or equivalent benefits even if serving 320 aMW.

c. Rate Charged for Power Deliveries

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

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smelter to survive and to preserve the more than 500 smelter jobs and 1,500 other jobs that are dependent upon Intalco receiving BPA's cost-based power."

[8] See section 4.1.3 of the Block Contract limiting GNA's access to a contract offer. See BPA's Block Contract offered to CFAC on December 14, 2009 and posted on BPA's external website.

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.[9] 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

[9] Comments appearing in this format, with an alphabetical prefix “CFA,” refer to the comment period closing on February 20, 2009, which received comments on an amendment to the CFAC’s contract which provided for service through the balance of FY 2009.

the Administrator's right to interrupt or curtail sales under the IP rate. 16 U.S.C. § 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.

d. Term of the Block Contract

The December Draft Contract developed for Alcoa (but not executed) had a proposed term of 17 years beginning October 1, 2011, and ending September 30, 2028, the same duration as BPA's other long-term power sales contracts that were executed in 2008 with BPA's public preference and other customers.

During subsequent negotiations between BPA and Alcoa, and after considering comments received, BPA has decided to reduce the 17-year term to seven years. BPA's primary interest with respect to the length of the new contract was that it not be so long that it exceeded BPA's risk tolerance for insuring adequate inventory to serve the load within a specified cost. For its part, Alcoa's primary concern was that the term be of sufficient duration to give Alcoa an opportunity to recover losses it has incurred at the Intalco Plant and to justify making capital investment in the Intalco Plant. Under the appropriate market conditions, Alcoa feels it should be able to recover losses incurred, within the latter years of a seven year agreement. Alcoa also indicated that a contract term of 10 years or more would allow it to make capital investment at the Intalco Plant. Alcoa encouraged BPA to offer at least a seven-contract and to consider what steps it could take to put in place a 10-year contract.[10] BPA has decided to offer a contract with a seven year term.

NRU commented that the structure of the contract makes it difficult to determine if sales under the Block Contract will be "in the money." NRU at 1. Canby requested BPA to conduct an economic analysis prior to the end of the 19-month period to assess whether BPA made money on the contract and whether BPA's public power customers subsidized BPA sales to Alcoa, and that the results of the economic analysis could be used in establishing service for the subsequent 5-year contract period. Canby at 10. Nearly all of BPA's rate setting is based on forecasts without specifically adjusting for what actually happens relative to each specific forecast. Rather, what actually happens collectively is covered by negative and positive adjustments to BPA's financial reserves, as well as rate adjustments, if needed. Depending on whether BPA is worse off or better off, relative to the forecast, at the end of the rate period, the results will be reflected in BPA's financial reserves and become an issue for treatment in subsequent rate cases.

WP-10 rate case models were used to establish the term of the Initial Period of the Block Contract with only a gas forecast update. BPA is satisfied the rate case models and the updated gas forecast used in the Equivalent Benefits Test sufficiently establishes the

[10] See letter to Allen Burns from Mike F. Rousseau, dated June 22, 2009, at.2.

Initial Period term of the contract without going back and making retroactive adjustments. BPA has decided not to conduct an economic analysis prior to the end of the Initial Period.

Snohomish commented that a Transition Period of a full year "is far too long" and stated that "BPA should already have the economic models in place to make this determination, and therefore should be able to do so in a matter of months, not a full year." Snohomish at 6. The contract enables BPA to establish the Transition Period from as short of a duration as six months and as long as 12 months. This provides BPA the flexibility to establish the duration needed to accomplish what might be required in the event there is a Transition Period. In the event there is a Transition Period BPA may have to do more than run economic models. BPA will need to evaluate future IP rates, forward power market prices and then finally determine if it can provide service to Alcoa within the Cost Caps negotiated within the Block Contract. BPA has decided to include a Transition Period not to exceed 12 months.

Snohomish also commented that language in the Block Contract suggests "the contract could terminate after the end of the Initial Period, and be revived after the passage of some unspecified period of time." Snohomish at 6. The provision commented on refers to a Transition Period that begins during the Initial or Extended Initial Period and extends beyond the end of those periods. If the Block Contract terminates because the Initial or Extended Initial Period ends without the Transition Period starting before or at the end of the Initial or Extended Initial Period, the terminated contract cannot be "revived" by a Ninth Circuit Opinion.

Snohomish urged BPA not to sign the Block Contract, and stated that "given BPA's derived benefit and the contingent nature of the Second Period, BPA has assumed a much higher level of risk with no demonstrated benefit by signing the DSI contracts at this time." Snohomish at 2. Snohomish is correct that the five-year Second Period is contingent, and is dependent on a future Ninth Circuit opinion that the Equivalent Benefits Test is not necessary and that BPA can provide service to Alcoa during the Second Period within the Cost Caps established in the Block Contract. For reasons stated elsewhere in this ROD, BPA believes the cost caps and other provisions of a Second Period are justified and adequately balance risks and benefits.

e.   Cost Caps

The Block Contract contains cost caps applicable to any Transition Period and Second Period. See Block Contract section 7. The level of the cost caps, and the manner in which BPA will evaluate whether the cost of service to Alcoa is equal to or less than the applicable cost caps, are specified in Exhibit B of the Block Contract. The cost caps will apply only to BPA's evaluation of whether it will provide service under the Block Contract during the Transition and Second Periods. This is because service to Alcoa under the Block Contract during the Initial Period, any increase in the level of service from 285 aMW to 320 aMW, or any extension of the term of the Initial Period, is contingent on BPA determining that it will achieve Equivalent Benefits from such service. Therefore, the cost caps are unnecessary during the Initial Period or any Extended Initial Period and would provide no additional risk mitigation to BPA.[11]

Comments raised a number of objections to the Cost Cap provision. PPC stated that it is not clear "whether BPA intended the cost caps to be an alternative to, or backstop to the Equivalent Benefits test," adding that in multiple places the contract "refers to instances where both the Equivalent Benefits test and the Cost Caps could be met," which implies that the Equivalent Benefits test could be complied with even if BPA were losing up to $330 million on the transaction." PPC at 7. ICNU made a similar point, stating that "[I]t is entirely inappropriate to include in the contract the 'Second Period' with the associated 'cost caps' that by their terms impose as cost on BPA's customers for service to the DSIs—a plain and admitted violation of the 9th circuit's decision." ICNU at 5.

BPA agrees that the draft sent out for public comment was unclear on this point. The final version has been changed to clarify that Cost Caps are not applicable to the Initial Period, or Extended Initial Period, if any, because BPA has determined that the benefits of the transaction exceed the cost. The Cost Caps could apply in the Transition and Second Periods of the Block Contract, but only if the Ninth Circuit clarifies its earlier opinions in a manner that would permit or require BPA to apply a test less stringent than the Equivalent Benefits Test. In that eventuality, BPA believes service to Alcoa of 320 aMW during a Transition and Second Period, at a cost that is within the Cost Caps, is in accordance with BPA's policy objectives of providing a reasonable level of service to an historical customer class without placing undue upward pressure on the rates of other customers.

WPAG argues that there is no limit on potential monetary losses during the Initial Period, and that neither the Equivalent Benefits Test nor the Cost Caps limit BPA's actual monetary losses since they are based on forecasts. WPAG at 5. PPC makes a similar argument. The consequence of WPAG's argument is either that (1) BPA may never serve DSI load because it can never know with absolute certainty that its forecast of the costs and benefits associated with a DSI transaction will, in fact, match actual costs and benefits, or (2) BPA may only serve the DSIs if it recovers its actual costs of service. The latter argument, essentially a rates argument, has already been addressed above. Regarding the former, nothing in *PNGC I* or *PNGC II*, or in the Northwest Power Act, prohibits BPA from entering into a transaction with a DSI customer (or with any other customer) unless the costs and benefits of the transaction can be locked-in with absolute certainty. Such a requirement does not comport with a commodities business, which by definition requires buyers and sellers to forecast, as part of any transaction, both availability and market price for the commodity in question. In simplest terms, this is what BPA does every time it establishes its rates, with risk mitigation tools established and deployed as necessary to assure total overall cost recovery, including repayment to the U.S. Treasury.

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[11] As explained in Part V herein, BPA has determined that it will achieve Equivalent Benefits from the sale of 285 aMW to Alcoa, increasing to 320 aMW, during the term of the Initial Period.

It is true, as WPAG and PPC argue, that once BPA makes a determination based on a forecast basis, and then executes the Alcoa contract, there is no contract provision that allows BPA to terminate the contract if the actual cost to provide service to Alcoa in the Initial Period exceeds the forecast. However, it is also the case that if actual costs are less than forecast, then BPA (and not Alcoa) receives that benefit. As indicated before, service to the DSIs during FY 2011-2012 was modeled in the WP-10 rate setting process at a level close to the amount offered in the Block Contract. Results from the rate case models forecast that the power purchases 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. All BPA rates are based on forecasts modeled in BPA's 7(i) ratesetting process. Therefore, for the Initial Period, BPA's rates (including the IP rate) have already accounted for the risk of actual costs exceeding the forecast amount.

Canby commented that section 2.2 of the draft Block Contract, which contemplated increasing the Cost Caps for Alcoa under certain circumstances, should be eliminated. Canby at 10. BPA decided the contingency for increasing the Cost Caps was a cumbersome concept, added unnecessary complexity, and removed this provision from Exhibit B. This concept was replaced with a simple, straightforward fixed benefit of $50.2 million per year for 320 aMW during the Transition period. The basis for the increase from $41 million per year is that during FY 2010 Alcoa self supplied power for 82 days prior to the start of the Block Contract, from October 1, 2009 through December 21, 2009. The portion of FY 2010's $41 million Cost Cap (also included in the August Draft and the November Draft contracts) associated with those 82 days was added to the Transition Period Cost Cap. The $50.2 million is equal to $41 million, plus the product of $41 million multiplied by 82 days divided by 365 days ($41,000,000 + [$41,000,000 * 82 / 365] = $50.2 million)

f. Termination and Take-or-Pay

In addition to the standard termination for default provisions, each party has the right to terminate the Block Contract under certain additional circumstances. BPA's additional termination rights primarily relate to cases where it has made a determination that it cannot serve Alcoa consistent with the Court's rulings or opinions, or at a cost that is at or below the cost caps. *See* Block Contract section 6.2. For its part, Alcoa may terminate the Block Contract at any time during the Initial, Extended Initial, or Transition Periods, on six months notice, and during any Second Period on 12 months' notice. *See* Block Contract sections 22.1.1.1 and 22.1.1.2. In each case, Alcoa retains some (in the case of termination during the Initial, Extended Initial, or Transition Periods) or all (in the case of a termination during a Second Period) of its take-or-pay obligation before the date of termination.

During the first three months of the 6 month notice period of a termination during the Initial, Extended Initial, or Transition Periods the take-or-pay obligation is 90 percent of Alcoa's then current firm power consumption. For the remaining 3 months of the 6 month notice period Alcoa is obligated to pay for only the firm power that it actually consumes during the ramp-down of plant operations. If Alcoa terminates the Block Contract during the Second Period, its take-or-pay obligation is for 12 months following such notice. Following the effective date of termination Alcoa has no further take-or-pay obligation and BPA has no further obligation to serve Alcoa during what would have been the remaining term of the contract. However, during the Second Period, BPA's forecast market prices for surplus sales are expected to exceed the IP rate. So while BPA bears some risk that prices could be lower, this is offset by BPA getting the more likely upside benefit.

Alcoa may terminate at any time, and on one day written notice, in the event BPA has made a determination pursuant to section 6.2 that it cannot serve Alcoa during a Second Period. See Block Contract section 22.1.2. Alcoa also may terminate in the event it has been billed directly, and paid to BPA, in excess of $2 million for certain environmental or regulatory costs. *See* Block Contract section 22.1.4. In each of the foregoing terminations, Alcoa has agreed (except in the case of a termination following a determination by BPA under section 6.2) that it will not restart the Intalco Plant until after the time when a Second Period would have otherwise ended. See Block Contract section 22.1.5.

WPAG commented objecting to the termination provisions, arguing that BPA has given Alcoa an unfettered termination right, which could expose BPA and its public utility customers to significant financial risk if such a termination were to occur during a period of low market prices. WPAG at 8. WPAG recognized BPA's assertion that protection is provided by a provision that prohibits re-start of operations until the end of the Second Period if the termination right is exercised, but insists that BPA's argument is flawed in that the prohibition would apparently not apply if the smelter is operating at the time Alcoa exercises its termination right (i.e., no "restart" is required). BPA believes the intent of the Block Contract is clear. If Alcoa terminates, except for terminations pursuant to section 6.2 of the Block Contract, Alcoa cannot operate the Intalco Plant for what would have been the remainder of the term of the Block Contract. *See* Block Contract section 22.1.5.

WPAG also argues there is no survivability language, which means that "when Alcoa terminates the Block Contract section 22.1.5 will be terminated along with the rest of the Block Contract." WPAG at 8. In fact, the term section of the Block Contract does contain survivability language, and an additional survivability provision was added at section 22.1.6. in response to the concerns expressed by WPAG.

BPA is confident that it can manage the risks associated with periods following termination of the Block Contract by using the same strategies outlined in the Curtailments and Liquidated Damages section below.

g. Curtailment and Liquidated Damages

While Alcoa's obligation under the Block Contract is generally take-or-pay, but Alcoa may curtail its load pursuant to the terms and conditions specified in section 9 of the Block Contract. During such periods of curtailment Alcoa's take-or-pay obligation is excused, and Alcoa is not liable for any losses (liquidated damages) BPA may incur in remarketing such curtailed power, nor is Alcoa entitled to share in any gains that BPA may receive as a result of remarketing.

Several parties in comments questioned why Alcoa is not obligated to pay BPA damages in the event BPA accrues less revenue from remarketing power during a curtailment of DSI load than it would have received from selling such power to Alcoa under the Block Contract.

PPC commented that the Block Contract contains no take-or-pay provisions. PPC at 7. The Block Contract is clearly structured as take-or-pay, but BPA has modified its earlier version of the Block Contract to clarify that, except for periods of curtailment, the sale and purchase is subject to take-or-pay requirements. Additionally, PPC objected to the inclusion of curtailment rights, stating the inclusion of curtailment rights in the contract essentially excludes any obligation for DSIs to pay BPA during times they do not operate their plants, and that in such instances BPA would be left unloading power in the market instead of selling it to the DSIs. PPC at 2. Furthermore, PPC argues that BPA's forecasts show prices for both aluminum and power prices as being low, "there may be a correlation between a DSI's decision to curtail and a low market in which BPA would have to resell such power." *Id*.

Other comments similarly argue the curtailment provisions create an unacceptable level of risk to BPA, and that, according to its own forecast of market prices, BPA will always suffer a financial loss on occasions of curtailment. E.g., WPAG at 6 (BPA's analysis shows that sales of power on the market will generate less revenue than if such power were sold to Alcoa, based on BPA's analysis any curtailment by Alcoa of BPA power deliveries are virtually assured to generate losses).

In addition, several parties commented that waiving Alcoa's take-or-pay obligation during periods or curtailment and not charging Alcoa any damages in the event BPA remarkets curtailed power at a loss, is inconsistent with how BPA addressed this issue in the recently executed contract with DSI customer Port Townsend. It is true Alcoa does not pay damages during periods of curtailments while Port Townsend does. A key reason for this difference in service concepts is that Port Townsend has unlimited curtailment rights while Alcoa's curtailment rights are limited. Alcoa can curtail for only a maximum of 24 months and under certain circumstances for a maximum of just 18 months.

BPA also agreed to include curtailment flexibility and waive Alcoa's take-or-pay obligation and not impose a liquidated damage obligation (i.e., an obligation to pay damages to BPA equal to any negative difference between IP revenues and the revenues BPA receives from remarketing curtailed power) during a curtailment on the basis that

Alcoa cannot replace BPA's power with power from another source and that during any curtailment period Alcoa must maintain certain employment levels. *See* Agreement section 9.2. On average, during the Initial Period, BPA would be in no worse position with regard to reselling the power into the market than had BPA not entered into the Block Contract to begin with. The contract provides Alcoa with the right to curtail its purchases for a maximum of 24 months. This 24 month maximum is limited further during the Second Period. Alcoa may only curtail purchases for 18 months during the Second Period, provided the 24 month overall limit is not exceeded. Without exercising its curtailment rights under the Block Contract Alcoa must pay for the full contract amount.

BPA is confident that it can manage the risks associated with periods of curtailment. Curtailments are limited to 24 months overall and 18 months within the Second Period. During the Initial and Extended Initial Period, if any, BPA plans to serve this load from existing inventory and does not expect to make long-term purchases. For this reason, BPA will not be in a position of having to dispose of significant amounts of power it had specifically acquired to serve Alcoa. Thus, during a curtailment BPA will market its remaining inventory as though the Block Contract was never executed, meeting its other firm contractual load obligations and then selling into the market. Therefore there is no additional risk resulting from this contract as compared to a scenario where BPA had not entered into this contract.

During the Transition Period or Second Period, while BPA may need to acquire some power, and such acquisitions are anticipated to be short-term purchases and BPA probably will not acquire power equal to the full contract amount since, again, BPA's existing system is expected to partially supply the load. Therefore, during a curtailment any power acquired to provide service to Alcoa is expected to be less than the full contract amount and for durations less than the Second Period reducing the risk of BPA being in a position of having to dispose of amounts of power equal to 320 aMW. BPA's forecast market price for power is expected to exceed the IP rate after the Initial Period and any Extended Initial Period. Therefore, even if BPA has purchased power in this timeframe to support the Alcoa sale, and Alcoa were to curtail or terminate deliveries, BPA has a greater probability of having a benefit by increasing revenues from reselling the power in the market at prices above the IP rate, rather than incurring costs from remarketing at a lower rate. While there is a low probability that market prices in this timeframe could be below the IP rate, resulting in a loss of revenues, the probability is greater that market prices and revenues will be higher, resulting in a net benefit.

h. Credit Support

Alcoa is obligated, at BPA's request, to arrange for BPA to be provided with a $30 million standby letter of credit, issued in a form and by a bank acceptable to BPA, and to have issued, at BPA's request, replacement standby letters so that a letter of credit will be in place if BPA determines such protection is necessary.

WPAG argues that, in spite of being able to call upon Alcoa to provide a letter of credit, BPA has assumed risks of non-payment, and that several of BPA's DSI customers have defaulted on their payment obligations to BPA and filed for bankruptcy protection. WPAG at 7. WPAG correctly points out that Alcoa is obligated, at BPA's request, to arrange for BPA to be provided with a $30 million standby letter of credit, equal to 103 days of power, calculated using the highest monthly average IP rate, so that a letter of credit is in place if BPA determines such protection is necessary. *See* Agreement section 21.8.1. BPA may seek additional performance assurance from Alcoa to the extent Alcoa's financial responsibility or performance viability become unsatisfactory to BPA. See Agreement section 21.8.3.

Some parties commented that BPA required more credit assurances from Port Townsend. BPA agrees that its payment assurance approach is different with Alcoa than is with Port Townsend. Port Townsend's parent company recently came out of Bankruptcy in 2007, whereas, Alcoa Inc. has maintained an investment grade rating since 1989. Even prior to Port Townsend's bankruptcy filing, Port Townsend was rated multiple notches below investment grade. For these reasons, Port Townsend is required to prepay monthly for its minimum take-or-pay purchase amount (13 aMW) and to post an additional deposit with BPA. The deposit is equal to the product of the difference of it maximum monthly purchase amount (20.5 aMW) minus the minimum take-or-pay amount times the highest monthly IP rate. The sum of the prepayment and the deposit is equal to or greater than the payment for power before it is delivered, mitigating account receivable risk of full payment prior to the start of deliveries. Alcoa is a publicly traded company with a bond ratings from Standard & Poor's, Moody's, and Fitch of BBB- rating. According to default rates published in the 2008 Corporate Default and Recovery Rates, 1920-2008 by Moody's and a similar issued by Standard & Poor's, Alcoa Inc. has a lower estimated default probability than the other DSIs. For this reason, Alcoa in not required to make a prepayment. But to help assure payment, BPA may request, and Alcoa is then obligated to post a $30 million letter of credit. These different payment assurance provisions are appropriate and provide the right balance for payment assurance.

It is not clear what risk WPAG believes BPA is taking in this respect, unless WPAG is arguing that there is a risk that Alcoa would owe BPA more than $30 million. A standby letter of credit represents an irrevocable and unconditional promise by the issuing bank to pay on demand to a beneficiary, in this case BPA, that is independent of the underlying Block Contract by and between BPA and Alcoa. BPA's right to draw on such a letter of credit is not dependent on Alcoa's financial condition. In the event Alcoa defaults on any payment obligation to BPA when due, BPA can, and will, draw on the letter of credit in the amount of such payment default. In addition, to the extent that WPAG is suggesting the amount of the letter of credit is insufficient and should cover all conceivable BPA exposure, it is not standard industry practice to require that a counterparty post security equal to the full notional value of the underlying transaction, which in the case of the Block Contract would equal approximately $700 million dollars, as this would require companies to post unreasonable amounts of collateral.[12] The letter of credit provisions in

[12] In the case of a power sales contract, the notional value would be calculated by multiplying the maximum number of megawatts sold (in this case 320 MW), times the rate (in this case forecast for any

section 20.8 would cover BPA's exposure to a failure by Alcoa to pay for 103 days of power deliveries, but it is unlikely that BPA would permit Alcoa to default on its payment obligations for that long.

i. Section 4.3

WPAG argues that section 4.3 as originally proposed amounted to a continuing commitment by BPA to perform under a contract found to be illegal by the Ninth Circuit. WPAG at 4. PPC echoes WPAG's views and states that including the provision only tends to foster the notion that BPA does not recognize a need to strictly comply with the Ninth Circuit's ruling when it comes to efforts to deliver a benefit to the DSIs. PPC at 8.

BPA agrees with the criticism of this provision, and so has amended it to provide that the Block Contract terminates upon issuance of the Court's mandate, absent a judicial extension of the period that BPA can provide service. See Block Contract section 4.3.

j. Covenants

Alcoa has made certain covenants, including agreeing not to challenge the validity of the Block Contract, any determinations by BPA regarding Equivalent Benefits, or any BPA determination under Exhibit B. See Block Contract section 25.1. In addition, Alcoa has agreed not to request any surplus power from BPA during the term of the Block Contract, and not to challenge any proposed or actual sale of surplus power by BPA, or to challenge any rate adopted by BPA for the sale of surplus power. See Block Contract section 25.2. Finally, Alcoa agreed that it will waive any claims it may have under Contract No. 06PB-11744, as amended, in the event BPA determines on remand in *PNGC I* and *PNGC II* that no payments are owing to or from either party under such contract, but that such waiver will be of no force or effect in the event that the Ninth Circuit issues its mandate in a case in which it has granted a petition for review and has issued an order that requires that payment be made. See Block Contract section 23.2

Some comments argued that the required covenants are inadequate. WPAG states the covenant in section 25.1 only covers BPA's Equivalent Benefit determination, and is silent with regard to any Forecast Net Cost determination made under Exhibit B, and that if BPA wishes to avoid unnecessary future litigation over the Block Contract, it should require Alcoa to covenant not to challenge any Forecast Net Cost and Cost Cap determinations. WPAG at 9. BPA has changed the language, as suggested by WPAG.

WPAG further argues that BPA should essentially use its bargaining power to extract further specific concessions, including agreement by Alcoa that it will pay to BPA any amounts BPA determines are payable by Alcoa to BPA as part of the remands in *PNGC I* or *PNGC II*. Others argued to similar effect. Snohomish 3-4; PPC, 5-6, 9; Canby 10; SUB 17.

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period not covered by current rates), times the number of hours in the maximum term of the contract (in this case 61,320 hours).

BPA does not believe that such heavy-handed tactics are necessary and declines to extract such a concession. No such concession has been required of BPA's preference customers in spite of the fact that Alcoa asserts that it is the one entitled to payment through the Lookback process. It would not be consistent with BPA's practices to require preference customers basically give up any legal argument that they may have to avoid collection in the event that Alcoa prevailed in its argument. BPA prefers, instead, to allow the process to run its course and leave all parties on an equal footing with respect to their respective legal positions.

In a similar vein, WPAG encourages BPA to use its perceived bargaining leverage to further weaken Alcoa's legal positions by forcing Alcoa to give up legal claims in exchange for BPA entering into a power agreement. WPAG at 8 (would make sound business sense for BPA to require Alcoa to waive its claims under the Prior Block Contract in order to obtain access to the benefits it will enjoy under the proposed Block Contract).

BPA disagrees that, as WPAG suggests, it makes good business sense, in the long run, to force a business partner to waive every conceivable right and make every possible concession simply because the sale to Alcoa is discretionary. BPA does not believe that *PNGC I*, *PNGC II*, or the Northwest Power Act require, or that it is otherwise consistent with principles of good faith and fair dealing, to place the preference interest groups at a legal advantage vis-à-vis the DSIs, simply because DSI service is now discretionary, and to require DSIs to waive any and all legal claims they may have before BPA will even consider providing service.

k. Damage Waiver Provision

The damages waiver provision in section 21.11 states:

> In the event the Ninth Circuit Court of Appeals or other court of competent jurisdiction issues a final order that declares or renders this Agreement, or any part thereof, void or otherwise unenforceable, neither Party shall be entitled to any damages or restitution of any nature, in law or equity, from the other Party, and each Party hereby expressly waives any right to seek such damages or restitution. For the avoidance of doubt, the Parties agree this provision shall survive the termination of this Agreement, including any termination effected through any order described herein.[13]

In both rounds of comments, a number of parties commented that the damages waiver provision in section 21.11 is illegal, inasmuch as BPA is obligated by law to recover any benefits conferred on Alcoa under the Block Contract in the event the Block Contract is found unlawful. See *e.g.*, September 9, 2009, comments of PPC at 9-10 (provision

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[13] The waiver clause in section 21.7 (severability provision) commented on by Snohomish provides that neither party shall be liable to the other for any damages associated with any term being severed from the Agreement.

unlawful, inappropriate, and "extremely ill-advised" in light of *PNGC I* and *PNGC II*; ICNU at 3 (as a government agency BPA obligated to recover funds illegally paid); WPAG at 5 (provision illegal, and BPA has provided no business rationale for including it); PNGC at 4 (waiver provision "startling" in light of *PNGC I* and *PNGC II*, and cannot be justified based on reciprocal nature of the waiver since Alcoa's prior claims shown to be meritless); WMG&T at 2 (waiver provision unconscionable); Snohomish at 3-4 (waivers inappropriate and should be replaced with express refund language).[14]

Specifically, PNGC argued in its comments in an earlier process regarding service to Alcoa that the waiver provision is unlawful because it "attempts to excuse BPA and its employees from complying with obligations that they have under the Property Clause of the U.S. Constitution to recover payments erroneously or illegally made." PNGC in DCA09 at 4. In support of this position, PNGC cited *Wisc. Cent. R.R. Co., v. United States*, 164 U.S. 190 (1896); *United States v. Wurts*, 303 U.S. 414, 415 (1938); and *Barrett Ref. Corp. v. United States*, 242 F.3d 1055, 1063 (Fed. Cir. 2001). In addition, PPC and Snohomish cite *Fansteel Metallurgical Corp. v. U.S.*, 172 F.Supp. 268, 270 (Fed. Cl. 1959) for the proposition that BPA is obligated by law to seek a refund of funds erroneously or illegally paid. PPC at 9; Snohomish at 4.

In *Fansteel*, the United States was seeking a refund from a contractor for overpayments by the government under a contract. The Court of Federal Claims (known then as the Claims Court) first noted that no "amendment of the contract exists under which [Fansteel] could retain the overpayment" apparently recognizing that there could be cases in which the United States would have agreed by contract to limit or waive any right to seek recovery of overpayments under a contract. *Fansteel Metallurgical Corp.* at 270 (Ct.Cl. 1959). Nevertheless, the court then went on to hold that

> when a payment is erroneously or illegally made it is in direct violation of article IV, section 3, clause 2 of the Constitution. Under these circumstances it is not only lawful but the duty of the Government to sue for a refund.

Id. As authority for this conclusion, *Fansteel* cites generally *Royal Indemnity Co. v. United States*, 313 U.S. 289 (1941), but it is not clear that *Royal Indemnity* either held that the government is duty bound to seek restitution for payments erroneously or illegally made and that it may never waive such right by contract, or even if it did, that the holding can be applied to a case where the erroneous or illegal payments were made pursuant to a contract that was entered into by a government official exercising contracting authority conferred upon him by Congress. In *Royal Indemnity*, an Internal Revenue Service employee, who had accepted a surety bond filed with him by a taxpayer pending resolution of a disputed tax assessment, consented to termination of the bond before the taxpayer had paid the full amount of his adjudicated tax. Citing article IV, section 3, clause 2 of the Constitution, the court stated that "the power to release or

[14] Several parties reiterated these comments regarding the waiver provision in comments filed on November 9, 2009. See, WPAG at 7; PPC at 8; ICNU at 4; Snohomish at 4.

otherwise dispose of the rights and property of the United States is lodged in the Congress" and held in light of this that

> [s]ubordinate officers of the United States are without that power, save only as it has been conferred upon them by Act of Congress or is to be implied from other power so granted.

Id. at 294 (citations omitted). The court went on to hold that the Internal Revenue Service agent that had released the surety bond was a "subordinate officer charged with the ministerial duty of collecting taxes" and that only the Commissioner of the Internal Revenue Service "is authorized to compromise a tax deficiency for a sum less than the amount lawfully due." *Id*. However, the BPA Administrator is authorized by statute to enter into power sales contracts with each direct service industrial customer, including Alcoa, and to amend, modify, adjust, cancel, compromise, or settle any claim arising thereunder. See, Bonneville Project Act, 16 U.S.C. §§ 832, 832a(f); Northwest Power Act, 16 U.S.C. §§ 839, 839f(a). Where the commercial content of those contracts is not prescribed by Congress, the law affords the Administrator substantial discretion to determine reasonable commercial terms. 16 U.S.C. § 832a(f); 16 U.S.C. § 839f. The Bonneville Project Act, 16 U.S.C. § 832d(b), expresses Congress's recognition that BPA's commercial contracts for the sale of power "shall be binding in accordance with the terms thereof . . ."

BPA believes the damage waiver provisions, which are mutual waivers, represent a fair allocation between the parties of the risk that the Block Contract may be invalidated in whole or in part, thereby serving to protect BPA from any damages claims that Alcoa may otherwise choose to pursue against BPA in such event. Parties entering into commercial contracts with BPA have a legitimate expectation that the contracts are within BPA's authority and that they should be able to rely upon them. Because the waiver provisions of the Block Contract fall within the scope of the broad contracting authority conferred on BPA by Congress, they do not implicate the constitutional considerations that form the basis of the holdings in *Royal Indemnity* and *Fansteel*.

The other cases cited in comments to support the proposition that the damage waiver provisions in the Block Contract are *per se* illegal are likewise inapposite. *United States v Wurts*, 303 U.S. 414 (1938), cited by PNGC, does not address whether the United States is *obligated* to seek to recover funds erroneously or illegally paid, but rather holds only that it can "by appropriate action" recover funds which its agents have wrongfully, erroneously or illegally paid, and that no separate statutory authority to pursue such an action is required. Likewise, *Wisc. Cen. R.R. Co., v. United States*, 164 U.S. 190 (1986) is cited by several parties for the general principle stated in that case that "parties receiving moneys illegally paid by a public officer are liable *ex aequo et bono* to refund them." *Id.* at 211.[15] But this is nothing more than restating a basic rule of equity jurisprudence that a party that has been unjustly enriched, as a general rule and absent any equitable defenses, will be required *as a matter of equity* to refund the value of the benefits conferred upon him. The case does not hold, or even discuss, the proposition by

[15] *Ex aequo et bono*: According to what is just and good.

PPC and others that the government is obligated *as a matter of law* to seek restitution in every such case, and is therefore as a matter of law prohibited from contractually agreeing to waive any right to do so.

In sum, BPA believes the waiver provisions are lawful and represent a reasonable allocation of the risks between the parties associated with an invalidation of the Block Contract, in whole or in part.

l. Reserves

Alcoa will provide power reserves to BPA under the Block Contract, as specified in the Minimum DSI Operating Reserve – Supplemental section of BPA's 2010 General Rate Schedule Provisions (referred to below as the "Supplemental Operating Reserve"), and section 10.1 and Exhibit F of the Block Contract. Alcoa will provide approximately 30 MW of power reserves, within a time frame, in an amount, and for a duration consistent with applicable reliability standards, and as specified by Exhibit F.

Several parties raised issues with respect to the power reserve provisions in the Block Contract. PPC, SUB, and PNGC questioned whether Alcoa would be able to provide the reserves contemplated by the Block Contract in the event BPA calls on them, and PNGC posited the reserves may be of little value given the relatively small size of the Alcoa load, while SUB noted that such reserves will be unavailable (and therefore worthless) in the event Alcoa curtails its load. PPC at 2; SUB at 7; PNGC at 2. For its part, Snohomish commented that the exhibit addressing the details of reserves in the Block Contract is unclear in several respects, including the return energy provisions, and that the contract appears to provide that Alcoa would receive compensation for providing reserves in addition to the reserves credit embedded in the IP rate. Snohomish at 2-3.

The amount and quality of the reserves Alcoa will provide under the Block Contract are consistent with statutory requirements and BPA's established rate schedules, and BPA believes will be made available by Alcoa if and when called on by BPA under the Block Contract. In fact, Port Townsend provided the same reserve product under its power contract for October 2009 that permitted BPA to interrupt deliveries of electric power to them in the event of a power system disturbance. As such, BPA and Port Townsend implemented a test procedure to ensure Port Townsend could provide the reserves as specified. Port Townsend successfully complied with multiple tests of their provision of reserves to BPA. As such, BPA expects to conduct a similar test procedure with Alcoa and BPA believes Alcoa – a relatively larger and more sophisticated participant in the electric power market – will also be compliant with the reserve provision of the Block Contract when called upon by BPA.[16]

In addition, in the WP-10 rate proceeding, BPA contemplated that the DSIs may provide a last-off-first-on reserve, but 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

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[16] Please refer to BPA's data responses in the WP-10 rate proceeding for further information regarding Alcoa's corporate expertise and experience with power reserves in other jurisdictions.

full value in that it can displace operational capacity that would have otherwise been utilized as Supplemental Operating Reserve:

> We agree that we must consider any lack of flexibility when we value the reserve service provided by the DSIs. The fact that the DSIs may provide a last-off-first-on reserve and the fact that this reserve can be deployed a maximum of once a day may result in a smaller value for these reserves as compared to the Initial Proposal value of Supplemental Operating Reserve. We have not fully analyzed all these limitations and considerations, but due to the IOUs' point that standing ready has value; the new information provided through BPA-AL-01, Exhibit 1; and the assumption that load-based reserves would be deployed last, 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. Therefore, we propose not to de-rate the value of reserve in this rate case.

WP-10-E-BPA-36, page 21. Even as a last-off-first-on reserve, BPA expected to call on the reserve provided by the DSIs as described below:

> BPA analyzed our contingency reserve obligation and contingency reserve deployment for FY 2008 to determine how frequently the capacity was fully used. To capture the capacity component, the contingency reserve obligation and deployment were analyzed within hour on a one minute time interval. On a minute by minute basis, the observed peak contingency reserve obligation was 752 MW and observed peak contingency reserve deployment was 599 MW during the study period. Analysis showed that the contingency reserves deployed were within 40 MW of the contingency reserve obligation nine times during the study period. The full amount of the contingency reserve obligation was deployed five times. The contingency reserve deployments that were within 40 MW of full requirements did not occur more than once a month and the duration of deployment ranged from seventeen (17) to seventy-five (75) minutes.

WP-10-E-BPA-36, page 33. BPA expects to call upon the reserves provided by Alcoa, if needed, at least as frequently as the reserve contemplated in the WP-10 rate proceeding.

As to the value of reserves from different sized loads, the compensation realized by Alcoa is through a rate credit of $0.80 per MWh. By including the compensation in the IP rate, the amount "paid" to a DSI is directly proportional to the size of its load. If it is a large load capable of providing more reserves, such as Alcoa, the DSI will be compensated with a larger amount of dollars. If the DSI is a smaller load, such as Port Townsend, it will provide fewer reserves, but will be compensated with a proportionally smaller amount of money.

SUB's comments with respect to the effect of a possible curtailment on the value of the reserves provided by Alcoa are misplaced. Compensation for power reserves is provided through the NPA section 7(c)(3) rate credit reflected in the IP rate, so during curtailments Alcoa is not making power purchases and will not receive a rate credit. If Alcoa elects to terminate the Block Contract, any power Alcoa elects not to take but pay for during the 12-month take-or-pay period will be assessed the IP rate plus $0.80 per MWh to account for the value of the reserves not provided when curtailed during the termination period, up to its take-or-pay obligation, for the curtailed power.[17] (*See* Block Contract section 22.1.1.2.)

As stated earlier, Alcoa will provide reserves to BPA under the Block Contract, as specified in the Minimum DSI Operating Reserve – Supplemental section of BPA's 2010 General Rate Schedule Provisions, and Exhibit F of the Block Contract.

m. Transmission

Snohomish (ALC090151 at 2) commented that it is not possible to estimate how the cost BPA might incur if BPA provides power to Alcoa at a Scheduling Point of Receipt that is different from Alcoa's Primary Point of Receipt might affect BPA's Equivalent Benefits analysis. These are costs that would be incurred as result of a request by BPA to change a point of receipt and to allow BPA to make power available to Alcoa at a point other than Alcoa's Primary Point of Receipt. This is a right that provides additional BPA flexibility to make power available to its customers. While operational decisions by BPA to maintain reliability and the efficiency of the Federal system are not a consideration of the Equivalent Benefits analysis, all customers will actually benefit from such improved reliability and efficiency.

n. BPA has the option of conducting additional public review

WPAG commented that section 4.4 of the Block Contract appears to commit BPA, without additional public process, to confer with Alcoa in the event that the Ninth Circuit issues an opinion that modifies or eliminates the Equivalent Benefits standard in order to determine how to proceed based on the Court's ruling. WPAG at 5. BPA did not mean to imply, in agreeing to confer with Alcoa regarding an order that modifies *PNGC I* and *PNGC II*, that it would not seek input from a broader set of interests if that were the case. Language has been added to section 4.4 of the Block Contract to make that clear. However, such a change in law would have immediate implications for the Block Contract. Thus, it makes sense, from an contract administration standpoint, to provide specifically for consultation between the two contracts signatories at that juncture.

[17] SUB commented that Alcoa is not providing reserves under curtailment situations and that the $0.80 per MWh reserve credit should be added back in when determining the take-or-pay amount. After considering this comment BPA decided to add the credit back into the calculation under those circumstances and changed the contract language accordingly.

V. THE EQUIVALENT BENEFITS TEST

As indicated above, a key element of BPA's response to *PNGC II* was to implement an Equivalent Benefits Test to determine whether BPA should offer a contract for the sale of power to Alcoa which is not contingent on future events. First, BPA determined that its need to acquire power to serve the Alcoa load during the Initial Period was limited because BPA anticipates serving the Alcoa load from inventory under most water conditions. Second, BPA determined that it could offer service for a period of approximately 17 months, during which term the forecasted benefits of the sale equal or exceed any forecast costs.

Some comments objected to serving the DSIs from inventory. Canby at 1, and 6-7. Others object to the use of the test. INCU at 2-4. Yet others object to the manner in which the test was conducted. For example, SUB contends that the gas forecast is out of date and that BPA's test "failed to address risk". SUB at 4-5. Moreover, Snohomish asserts that BPA's comparison should be to the forward market and not a forecast of future prices. Snohomish at 2. The following sections describe the elements of the Equivalent Benefits Test, detail the analysis conducted, and address the concerns expressed by the parties.

a. BPA is unlikely to incur costs from serving Alcoa during the Initial Period

BPA does not forecast the need to make purchases specifically to serve Alcoa during the Initial Period under the Block Contract under most water conditions, although, as explained below, BPA has forecast the need to make some purchases, including some normal "balancing" purchases, to meet its total load obligations over the FY 2010 through FY 2011 rate period, under critical (*i.e.*, very poor) water conditions.[18] Some comments questioned BPA's ability to provide power under the Block Contract without making additional market acquisitions. Specifically, Snohomish indicates that BPA's "…forecast of winter deficits raises the question whether the DSIs can be served from existing FBS inventory or whether balancing purchases and additional augmentation will be required from the market." (Snohomish at 2) In addition, Canby asserts that "BPA's 'Equivalent Benefits' test is faulty because BPA assumes the augmented federal power system is in surplus and has sufficient inventory (460 aMW) to supply Alcoa and CFAC in every month of the year under 1937 'critical water' conditions." Canby at 2. See also ICNU at 2; PNGC at 2; and Snohomish at 2-3.

Pursuant to BPA's most recent load and resources study contained in the 2009 Pacific Northwest Loads and Resources Study ("2009 White Book"), which forecasts loads and resources for both the Federal system and the region as a whole for the 10-year period OY

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[18] 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.

2010-2019,[19] BPA is forecast to have a surplus of approximately 1,731 aMW and 1,526 aMW on an average annual basis under the middle 80 percent of the historical water conditions for the OY 2010 and OY 2011 respectively. The Initial Period of the Block Contract includes just over 9-months in FY 2010 and just under 8-months in FY 2011. See 2009 White Book, Table 8 at 40, and Exhibits 11-12 at 104-107. Alcoa's load under the Block Contract represents approximately 20 percent of that forecast surplus. Moreover, the 2009 White Book reflects a surplus of 102 MW and deficit of 170 MW on an average annual based under 1937-Critical Water Conditions in OY 2010 and OY 2011, and does so assuming no augmentation and no service to the aluminum smelter DSIs.[20]

In the recently completed WP-10 Wholesale Power and Transmission Rate Adjustment Proceeding (WP-10) BPA forecast surplus available for secondary sales of 1,694 aMW for FY 2010 and 1,751 aMW for FY 2011 (which together encompass the Initial Period of the Block Contract for which the Equivalent Benefits Test is employed). See Table 4.8.1: Secondary Sales, WP-10-FS-BPA-05A, at 88. The WP-10 rate proceeding also forecasts that BPA will be in load resource balance under 1937-Critical Water Conditions, as is explained in more detail below. Canby's assertion that the Equivalent Benefits test is faulty because, even though the "augmented federal system is in surplus" and "has sufficient inventory… under *1937* 'critical water' conditions", BPA is still short of power five months of the year in critical water conditions, is incorrect.

BPA has not claimed that the Equivalent Benefits Test is based on 1937-Critical Water Conditions. To the contrary, BPA has based the Equivalent Benefits Test, which is used solely to satisfy BPA's conservative interpretation of *PNGC II*, on its forecasts of average water in the 2009 White Book and the WP-10 Loads & Resources Study. Nonetheless, 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, WP-10-FS-BPA-01A at 10-13. However, another portion of BPA's rates, notably the Secondary Sales and Purchases, for FY2010 and FY2011 were set based on average water, specifically using the 1,694 aMW for FY 2010 and 1,751 aMW for FY 2011 referenced above, as evidenced by Tables 4.6.2, 4.8.1 and 4.8.2, WP-10-FS-BPA-05A at 77, 88-89.

BPA's forecast under average water in WP-10 takes into account certain market purchases, shown here, that BPA forecasts it may make, or has made, in order to meet its load obligations under critical (or very poor) water conditions in FY 2010 and FY 2011 (see Tables 4.8.2, 4.8.3, 4.8.4, WP-10-FS-BPA-05A, at 89-91):

	FY2010	FY2011
Balancing Purchases	193 aMW	149 aMW
Winter Hedging Purchases	~80 aMW	~80 aMW
Augmentation Power Purchases	476 aMW	680 aMW

[19] Operating Year (OY) in the White Book is the 12-month period August 1 through July 31. For example, OY 2010 is August 1, 2009, through July 31, 2010.

[20] 2009 White Book, page 40.

Even after adjusting out these purchases, 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 made to Alcoa. This does not precluded the fact that BPA may have to occasionally make short term purchases during certain times of the year, should below average water conditions occur and, in such instances, Alcoa's load could add to the amount BPA needs to purchase. *See also*, Loads and Resources Data Used in the Equivalent Benefits Test, Part V, section (e) of this Record of Decision below.

BPA attempted to summarize its expectation with a handout entitled *Table A-30: Federal Surplus/Deficit – By Water Year* during a meeting with Public Power interests on November 3rd.[21] Some commenters, like Canby at 5-6, may have concluded from the title alone that this so-called "Table A-30" was part of the WP-10 Loads & Resource Study. It is not. BPA neglected to properly title its handout. Nonetheless, the information contained in the handout is an accurate composite of materials included in the WP-10 rate proceeding and can be constructed easily by applying the energy analysis of the federal system load resource balance contained in the WP-10 Loads & Resource Study, Tables 2.3.1 and 2.3.2 (WP-10-BPA-01A at 10-13) to the federal hydro generation from the Risk Analysis and Mitigation Study Documentation, Tables 3 and 4 (WP-10-BPA-04B at 23-26).[22] At the bottom of the last page pertaining to each fiscal year in the handout entitled *Table A-30: Federal Surplus/Deficit – By Water Year*, BPA subtracted 402 aMW, representing the average annual megawatt amount of augmentation purchases that equally offsets the line entitled "DSI PSC 2002" under Non-Utility Obligations section of the table, from the surplus under the ranked average middle 80-percent water condition to demonstrate that BPA expected to be surplus even after removing augmentation for DSIs. This too illustrates that even after adjusting out the average annual megawatt amount of augmentation associated with DSI service, BPA expects to be surplus under average water conditions.

In any case, the WP-10 Loads & Resources Study includes 403 aMW for service to the DSIs, including at least 285 aMW of service to Alcoa (see Table 4.6.2, WP-10-FS-BPA-05A, at 77), and so BPA has already factored such sales into the above referenced table of possible FY 2010 and FY 2011 purchases.[23] In addition, total DSI load over the term

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[21] The handout can be found under the link entitled "Federal Surplus/Deficit – By Water Year (11/4/2009)" on BPA's website: http://www.bpa.gov/power/pl/regionaldialogue/implementation/documents/#SDSI.

[22] Exhibits similar to the composite result of information from the WP-10 rate proceeding used in the handout are also included in the 2009 White Book at 104-107. Those exhibits are presented in the same manner as the handout *Table A-30: Federal Surplus/Deficit – By Water Year*. While the assumptions used in the 2009 White Book are somewhat different than the WP-10 Loads & Resources Study as explained above, and in more detail therein, the presentation format is materially the same and BPA's conclusion also remains the same in that it expects to be surplus under average water conditions, and as such does not anticipate the need to alter its purchasing strategy for the sales made to Alcoa.

[23] It should be noted that Table 4.6.2: Summary of Revenues at Proposed Rates (WP-10-FS-BPA-05A at 77) does reflect 403 aMW of DSI service, while Tables 2.3.1 and 2.3.2: Loads and Resources: Federal System (WP-10-FS-BPA-01A at 10-13) reflect 402 aMW of DSI service.

of the Block Contract may well be less than this 403 aMW amount because another DSI, Columbia Falls Aluminum Company (CFAC) is currently shutdown, making market purchases in addition to those referenced above less likely.[24]

As introduced above, Snohomish suggests that BPA's rationale for the Winter Hedging Purchases included in the table above "…raises the question whether the DSIs can be served from existing FBS inventory or whether balancing purchases and additional augmentation will be required from the market." Snohomish at 2. Snohomish is correct that BPA's rationale for these Winter Hedging Purchases was "increasing amounts of forecast HLH energy deficits during winter months under many water conditions." (WP-10-E-BPA-34 at 2) BPA continues to believe that the Winter Hedging Purchases are a prudent hedge. As a result, BPA is able to cost-effectively meet the load obligations of our customers, including Alcoa, under more adverse water conditions during HLH in the winter months. That said, BPA does not preclude actually making balancing purchases or augmentation purchases to serve customers' load obligations, including Alcoa, that were projected to be necessary under 1937-Critical Water Conditions used in WP-10. BPA simply expects that the actual need for such purchases to serve all of its customers, including Alcoa, is limited due to the surplus inventory we expect to have under most water conditions. See Tables 4.6.2, 4.8.1 and 4.8.2, WP-10-FS-BPA-05A at 77, 88-89 and Tables 3 and 4, WP-10-BPA-04B at 23-26.

NRU commented regarding Slice/Non-Slice cost shifts. ALC090151 at 1. To the extent BPA's most recent forecast used in the Equivalent Benefits Test is correct and the net cost of DSI service is well below the $38 million average annual that is already in rates (including the rates for both non-Slice and Slice purchasers), the benefits from such reduced costs would accrue solely to non-Slice purchasers. The 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.[25]

In addition, Snohomish commented that "…BPA assumed 30-minute persistence forecasting for wind. This persistence level uses the least amount of balancing reserves from the FBS to follow wind." It is true that both the 2009 White Book and the WP-10 Loads & Resource Study – and the materials cited from them herein – use regulated

[24] *Columbia Falls Aluminum Ceases Operations*, Flathead Beacon, October 31, 2009.

[25] NRU requests a determination that the Alcoa contract would not result in a cost shift between non-Slice and Slice purchasers. BPA cannot give NRU any assurance that there will be no cost shifts between non-Slice and Slice purchasers. In the WP-10 rate proceeding, issues regarding the risks inherent in assuming service to DSIs in the ratesetting process were raised by a number of parties. In response, BPA proposed an automatic rate adjustment mechanism that would have adjusted rates, including rates for both non-Slice and Slice purchasers, to account for changes in purchase power costs and IP rate levels. This proposal was forcefully opposed by a large number of BPA's preference customers. As a result, BPA declined to adopt a rate adjustment mechanism to account for DSI service costs. See WP-10 ROD, WP-10-A-02 at 225-226. Because any purchase power costs for DSI service, if any are incurred, would be included in either augmentation expense or balancing purchase expense, BPA has no ability to pass these cost changes to Slice purchasers through the annual Slice True-Up Adjustment Charge. Therefore, any changes in BPA's costs and revenues resulting from service to DSIs would fall solely on non-Slice purchasers.

hydro generation projections that reflect operating reserve levels associated with 30-minute wind persistence scheduling accuracy forecasts.[26] However, Snohomish goes on to assert that "…the FY10-11 rate case adopted both the 30- and 45-minute persistence forecasts" and that "[i]f the region is not successful in using 30-minute persistence to forecast wind generation, additional balancing reserves from the FBS would be required, reducing the amount of energy available from inventory." Snohomish at 3. BPA does not expect this to be the case given operating protocols BPA has put in place to adjust wind fleet operations to enable BPA to keep reserves at a level based on a 30 minute persistence forecast. BPA set its rates in WP-10 based on 30-minute persistence and operates its system to the same level of reserves.[27] Furthermore, BPA continues to believe the region will be successful in using 30-minute persistence to forecast wind generation and that additional balancing reserves from the FBS are not likely to be required. Thus, BPA does not anticipate the need to make specific additional purchases to serve the Alcoa load under average water conditions. Nevertheless, if any additional purchases become necessary, the average market price during the Initial Period of the Block Contract, as explained below, is expected to be at a level where the benefits of serving Alcoa equal or exceed the cost of buying the power.

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

For the reasons outlined in this section, BPA forecasts that the revenues it will accrue from the sale to Alcoa of 285 aMW or power, (which pursuant to a request by Alcoa under the Block Contract will increase to 320 aMW effective by March 2010), at the IP rate during the Initial Period, will exceed by approximately $10,000 the forecast revenues BPA could otherwise obtain from selling that power into the market for the Initial Period. See Tables 1-6 below. As a consequence, BPA believes service to Alcoa under the Block Contract is consistent *PNGC II*, that service to a DSI only can be provided if benefits equal or exceed costs.

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 rates for each month. BPA has calculated revenues under the Block Contract based on an initial sale of 285 aMW, increasing to 320 aMW in March 2010 as outlined in Table 1, of firm power each hour to Alcoa under the IP-10 rate schedule beginning December 22, 2009, the commencement of Firm Power deliveries pursuant to the Block Contract, and ending on May 26, 2011.[28] The energy entitlements are the

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[26] See 2009 White Book, at 23 and WP-10-FS-BPA-05A, at 77.

[27] "Accordingly, BPA will set the rate based on 30-minute persistence and will operate its system to the same level of reserves. BPA will also post the amount of reserves it is carrying on a regular basis to provide transparency to those who are worried BPA will offer a low rate but carry a higher amount of reserves." WP-10-A-02 at P-5.

[28] Prior to receiving Alcoa's letter requesting an increase to 320 aMW reflected in the monthly Demand (kW) in Table 1 above, BPA completed a substantially similar analysis of equivalent benefits based on a flat sale of 285 aMW commencing December 22, 2009 and ending on May 31, 2011. That analysis, included as Attachment F to this Record of Decision, forecasted that the revenues accruing to BPA from

projected amounts of megawatt-hours to be sold by diurnal period each month. The demand entitlement is the megawatt amount consumed during the hour of BPA's system peak. 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:

TABLE 1 - Usage and Rates

	Alcoa Ferndale Usage			IP-10 Rates		
Month	Demand (kW)	HLH (MWh)	LLH (MWh)	Demand ($ / kW)	HLH ($ / MWh)	LLH ($ / MWh)
Dec-09	285,000	118,560	93,480	$2.30	$35.24	$31.13
Jan-10	300,000	120,000	103,200	$1.96	$38.46	$32.24
Feb-10	315,000	120,960	90,720	$1.99	$37.72	$31.73
Mar-10	320,000	138,240	99,520	$1.85	$35.94	$30.08
Apr-10	320,000	133,120	97,280	$1.74	$32.23	$26.95
May-10	320,000	128,000	110,080	$1.44	$31.69	$22.29
Jun-10	320,000	133,120	97,280	$1.32	$31.18	$23.29
Jul-10	320,000	133,120	104,960	$1.61	$33.33	$28.66
Aug-10	320,000	133,120	104,960	$1.89	$37.31	$31.40
Sep-10	320,000	128,000	102,400	$1.96	$36.49	$32.26
Oct-10	320,000	133,120	104,960	$2.05	$31.92	$27.01
Nov-10	320,000	128,000	102,720	$2.19	$33.33	$29.58
Dec-10	320,000	133,120	104,960	$2.30	$35.24	$31.13
Jan-11	320,000	128,000	110,080	$1.96	$38.46	$32.24
Feb-11	320,000	122,880	92,160	$1.99	$37.72	$31.73
Mar-11	320,000	138,240	99,520	$1.85	$35.94	$30.08
Apr-11	320,000	133,120	97,280	$1.74	$32.23	$26.95
May-11	320,000	128,000	110,080	$1.44	$31.69	$22.29
Jun-11	320,000	133,120	97,280	$1.32	$31.18	$23.29

the sale of 285 aMW to Alcoa at the IP rate would exceed by approximately $151,000 the forecast revenues BPA could otherwise obtain from selling that power into the market.

TABLE 2 - BPA's Projected Revenue

Month	Revenues by Rate Determinant			Projected IP Revenue	
	Demand ($)	HLH ($)	LLH ($)	Month ($)	Cumulative ($)
Dec-09	$655,500	$4,178,054	$2,910,032	$7,743,587	$7,743,587
Jan-10	$588,000	$4,615,200	$3,327,168	$8,530,368	$16,273,955
Feb-10	$626,850	$4,562,611	$2,878,546	$8,068,007	$24,341,962
Mar-10	$592,000	$4,968,346	$2,993,562	$8,553,907	$32,895,869
Apr-10	$556,800	$4,290,458	$2,621,696	$7,468,954	$40,364,822
May-10	$460,800	$4,056,320	$2,453,683	$6,970,803	$47,335,626
Jun-10	$422,400	$4,150,682	$2,265,651	$6,838,733	$54,174,358
Jul-10	$515,200	$4,436,890	$3,008,154	$7,960,243	$62,134,602
Aug-10	$604,800	$4,966,707	$3,295,744	$8,867,251	$71,001,853
Sep-10	$627,200	$4,670,720	$3,303,424	$8,601,344	$79,603,197
Oct-10	$656,000	$4,249,190	$2,834,970	$7,740,160	$87,343,357
Nov-10	$700,800	$4,266,240	$3,038,458	$8,005,498	$95,348,854
Dec-10	$736,000	$4,691,149	$3,267,405	$8,694,554	$104,043,408
Jan-11	$627,200	$4,922,880	$3,548,979	$9,099,059	$113,142,467
Feb-11	$636,800	$4,635,034	$2,924,237	$8,196,070	$121,338,538
Mar-11	$592,000	$4,968,346	$2,993,562	$8,553,907	$129,892,445
Apr-11	$556,800	$4,290,458	$2,621,696	$7,468,954	$137,361,398
May-11	$460,800	$4,056,320	$2,453,683	$6,970,803	$144,332,202
Jun-11	$422,400	$4,150,682	$2,265,651	$6,838,733	$151,170,934

c. Comparison of net revenues under the Block Contract to forecast revenues that might be obtained by selling an equivalent amount of power on the market.

BPA routinely shapes its inventory to meet the need of its portfolio of contracts and sells its surplus inventory by purchasing and selling in the Pacific Northwest power market as described in BPA's WP-10 rate proceeding.[29] BPA established its forecast of Mid-C electricity prices in the WP-10 rate proceeding to value these purchases and sales.[30] For the period covered by the Block Contract BPA has updated its natural gas forecast from that used in BPA's WP-10 rate proceeding to forecast electricity prices to reflect a more contemporary understanding of natural gas fundamentals and to be consistent with the natural gas forecast used in *Summary of BPA's Analysis of the Block Contract for Port Townsend* and BPA's draft Resource Program released September 30th.[31]

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[29] Refer 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)

[30] BPA employs 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.)

[31] 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

In the absence of the Block Contract initially selling 285 aMW of firm power to Alcoa's Intalco Plant every hour, and subsequently increasing that amount to 320 aMW, BPA would have one less firm power requirement sale in its aggregated portfolio load shape to meet; as such BPA would have at least 285 aMW of surplus energy to sell in the market. As illustrated in Table 3, BPA has forecast the revenues it would otherwise obtain from the market using the same forecasting methodology applied in the WP-10 rate proceeding to incorporate our updated forecast of natural gas prices in the development of our electricity price forecast used in this analysis of the Block Contract for Alcoa.[32]

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

	Forecasted Market		Forecasted Revenues Obtained from the Market			
Month	HLH Price ($ / MWh)	LLH Price ($ / MWh)	HLH ($)	LLH ($)	Month ($) (HLH + LLH)	Cumulative ($)
Dec-09	$30.61	$27.41	$3,629,276	$2,562,520	$6,191,795	$6,191,795
Jan-10	$34.13	$29.51	$4,095,483	$3,045,278	$7,140,761	$13,332,556
Feb-10	$34.46	$29.77	$4,168,308	$2,700,699	$6,869,007	$20,201,563
Mar-10	$33.92	$29.16	$4,689,678	$2,901,972	$7,591,650	$27,793,213
Apr-10	$32.95	$28.05	$4,386,230	$2,729,010	$7,115,239	$34,908,452
May-10	$33.93	$24.45	$4,343,287	$2,691,520	$7,034,807	$41,943,259
Jun-10	$34.33	$26.33	$4,569,908	$2,561,356	$7,131,264	$49,074,523
Jul-10	$37.33	$32.18	$4,969,150	$3,377,181	$8,346,331	$57,420,854
Aug-10	$42.48	$35.63	$5,654,607	$3,739,247	$9,393,854	$66,814,708
Sep-10	$42.86	$38.00	$5,485,936	$3,890,844	$9,376,780	$76,191,488
Oct-10	$43.31	$36.85	$5,765,479	$3,867,640	$9,633,119	$85,824,607
Nov-10	$45.36	$40.59	$5,806,297	$4,169,181	$9,975,478	$95,800,085
Dec-10	$48.81	$43.42	$6,497,553	$4,557,662	$11,055,215	$106,855,300
Jan-11	$50.70	$42.13	$6,489,767	$4,637,348	$11,127,115	$117,982,415
Feb-11	$50.78	$42.80	$6,240,232	$3,944,303	$10,184,535	$128,166,950
Mar-11	$49.33	$40.83	$6,819,456	$4,063,290	$10,882,746	$139,049,696
Apr-11	$46.35	$38.79	$6,169,651	$3,773,488	$9,943,140	$148,992,836
May-11	$47.15	$32.65	$6,035,240	$3,594,350	$9,629,590	$158,622,426
Jun-11	$46.50	$33.58	$6,190,070	$3,267,141	$9,457,211	$168,079,637

Net Benefit (IP – Market)

understanding of natural gas market fundamentals caused a lowering of its natural gas price forecast in 2010 and an increase in 2011. 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, c) record amount of natural gas in storage, d) reduced risk of hurricane impact on supply now that the 2009 hurricane season is nearly over. (See also Short-term Energy Outlooks from the EIA for September and October that have reduced their forecasted Henry Hub Spot Price average for 2010 to $4.78 and $5.02 per Mcf respectively [or $4.64 and $4.87 per MMbtu using EIA's conversion of 1 Mcf = 1.031 MMbtu], *Short-term Energy Outlook*, DOE EIA, September 9, 2009, page 1; *Short-Term Energy and Winter Fuels Outlook*, DOE EIA, October 6, 2009, p. 3.)

[32] 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.

BPA determined its net benefit of serving Alcoa's Intalco Plant at the IP rate for each month by subtracting the opportunity cost forecast to be obtained in the market 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 ($)	Net Revenue or (Cost) Cumulative ($)
Dec-09	$1,551,791	$1,551,791
Jan-10	$1,389,607	$2,941,399
Feb-10	$1,199,000	$4,140,399
Mar-10	$962,257	$5,102,656
Apr-10	$353,715	$5,456,370
May-10	($64,003)	$5,392,367
Jun-10	($292,532)	$5,099,835
Jul-10	($386,088)	$4,713,747
Aug-10	($526,603)	$4,187,145
Sep-10	($775,436)	$3,411,709
Oct-10	($1,892,959)	$1,518,750
Nov-10	($1,969,981)	($451,230)
Dec-10	($2,360,661)	($2,811,892)
Jan-11	($2,028,056)	($4,839,947)
Feb-11	($1,988,465)	($6,828,412)
Mar-11	($2,328,839)	($9,157,251)
Apr-11	($2,474,186)	($11,631,437)
May-11	($2,658,787)	($14,290,224)
Jun-11	($2,618,478)	($16,908,702)

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.

BPA has identified a number of tangible benefits to BPA that would not be achieved by a market sale of power compared to a sale to Alcoa under the Block Contract at the IP rate. BPA conducted an economic analysis to determine the value of those benefits and included them in its analysis of the net value of the Block Contract to BPA. 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.

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 to BPA of the reserves Alcoa is required to make available to BPA under the Block Contract. Sales at the IP rate reflect the value of a right for BPA to obtain contingency reserves.[33] 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.[34] As illustrated by 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 ($)	Cumulative ($)
Dec-09	$169,632	$169,632
Jan-10	$178,560	$348,192
Feb-10	$169,344	$517,536
Mar-10	$190,208	$707,744
Apr-10	$184,320	$892,064
May-10	$190,464	$1,082,528
Jun-10	$184,320	$1,266,848
Jul-10	$190,464	$1,457,312
Aug-10	$190,464	$1,647,776
Sep-10	$184,320	$1,832,096
Oct-10	$190,464	$2,022,560
Nov-10	$184,576	$2,207,136
Dec-10	$190,464	$2,397,600
Jan-11	$190,464	$2,588,064
Feb-11	$172,032	$2,760,096
Mar-11	$190,208	$2,950,304
Apr-11	$184,320	$3,134,624
May-11	$190,464	$3,325,088
Jun-11	$184,320	$3,509,408

Avoided Transmission and Ancillary Services Expenses

When BPA makes a DSI sale, the DSI customers – including Alcoa – cover the cost of transmission and ancillary services through their own transmission contracts. Market prices, on the other hand, assume power is delivered by the seller to Mid-Columbia trading hub (Mid-C). 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

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[33] 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.

[34] 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.

transmission products and services to deliver the surplus power it intends to sell. However, this 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 -– including the Block Contract with Alcoa. The planned transmission and ancillary services expenses to address both the expected expenses and their uncertainty were addressed in the WP-10 rate proceeding.[35] Since PS overall marketing strategy is to serve all its loads out of inventory and meet any power deficits with short-term purchases, the incremental transmission and ancillary services costs are avoided when BPA makes firm power IP sales to the DSIs.

PS valued these avoided transmission and ancillary services costs using the same methodology used in the WP-10 rate proceeding to establish the total costs and risks associated with PS' 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 DSI and DSI service of 372 aMW.[36] The average total monthly expense values of the 3,500 games were computed with and without service to the DSI and the differences were taken to determine the avoided PS transmission and ancillary services costs when PS makes these 372 aMW of IP sale(s) to the DSIs. For purposes of this analysis, Alcoa has been allotted 76.6% 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 in the Block Contract, and as depicted in Table 1 above, as compared to the 372 aMW forecasted for all DSI customers.

[35] 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.

[36]This number is comprised on 285 aMW for Alcoa, 70 aMW for Columbia Falls Aluminum Company, and 17 aMW for Port Townsend Paper Company.

TABLE 5b - BPA's Net Benefit Adjustments
Avoided Tx and Ancillary Service Costs

Month	Month ($)	Proportional Month ($)	Cumulative ($)
Dec-09	$149,883	$114,829	$114,829
Jan-10	$411,830	$332,121	$446,950
Feb-10	$323,594	$274,011	$720,961
Mar-10	$427,273	$367,546	$1,088,507
Apr-10	$546,922	$470,470	$1,558,978
May-10	$797,099	$685,676	$2,244,654
Jun-10	$706,870	$608,060	$2,852,714
Jul-10	$568,866	$489,347	$3,342,061
Aug-10	$127,860	$109,987	$3,452,049
Sep-10	$44,322	$38,126	$3,490,175
Oct-10	$39,191	$33,713	$3,523,888
Nov-10	$73,161	$62,935	$3,586,823
Dec-10	$150,605	$129,552	$3,716,375
Jan-11	$417,282	$358,952	$4,075,328
Feb-11	$318,185	$273,707	$4,349,035
Mar-11	$412,095	$354,490	$4,703,525
Apr-11	$492,378	$423,551	$5,127,077
May-11	$765,645	$658,619	$5,785,696
Jun-11	$669,032	$575,511	$6,361,207

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 forecasted these increased revenues by reducing loads in the PNW by 372 aMW in each month for each of the 3,500 games AURORA simulated for the forecast used in Table 3 above. This lowered the mean price forecast by a 12-month average of $0.29 per MWh and by $0.41 per MWh for fiscal years 2010 and 2011 respectively.[37] The monthly difference resulting from this lower mean price forecast was then multiplied by BPA's monthly surplus energy from the WP-10 rate proceeding to determine the increased revenues available to BPA's surplus sales when BPA makes an IP sale(s) to the DSIs – including the Block Contract with Alcoa. For the purposes of this analysis, Alcoa has been allotted 76.6% 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 megawatt amounts in the Block Contract, and as depicted in Table 1 above, as compared to the 372 aMW forecasted for all DSI customers.

[37] AURORA 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.

TABLE 5c - BPA's Net Benefit Adjustments

Month	Demand Shift Month ($)	Proportional Month ($)	Cumulative ($)
Dec-09	$39,719	$30,430	$30,430
Jan-10	$146,279	$117,967	$148,397
Feb-10	$181,585	$153,762	$302,159
Mar-10	$279,051	$240,044	$542,203
Apr-10	$428,356	$368,479	$910,682
May-10	$1,347,534	$1,159,169	$2,069,850
Jun-10	$900,404	$774,541	$2,844,392
Jul-10	$519,495	$446,878	$3,291,269
Aug-10	$32,901	$28,302	$3,319,571
Sep-10	($25,231)	($21,704)	$3,297,867
Oct-10	$1,755	$1,510	$3,299,377
Nov-10	($29,249)	($25,160)	$3,274,217
Dec-10	$38,606	$33,210	$3,307,427
Jan-11	$453,911	$390,461	$3,697,888
Feb-11	$295,680	$254,348	$3,952,236
Mar-11	$651,012	$560,010	$4,512,246
Apr-11	$619,527	$532,927	$5,045,173
May-11	$1,548,290	$1,331,862	$6,377,035
Jun-11	$1,222,884	$1,051,943	$7,428,978

Conclusion of Equivalent Benefits Test

The preceding analysis demonstrates how the projected revenues BPA recovers from the 17-month IP sale to Alcoa (from December 22, 2009 through May 26, 2011) exceed by approximately $10,000 the forecasted revenues that BPA would otherwise obtain from the market. See Table 6 below. BPA's methodology for making this determination is based, to the extent possible, on modeling tools used in BPA's rate case. 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 insure the integrity of the results. BPA believes that it a reasonable assessment and that the concerns expressed in the comments have been fully considered and fairly evaluated.

TABLE 6 - BPA's Net Benefit after Adjustments

Month	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 ($)	Cumulative ($)
	BPA's Adjusted Net Revenue or (Cost)					
Dec-09	$1,551,791	$169,632	$114,829	$30,430	$602,156	$602,156
Jan-10	$1,389,607	$178,560	$332,121	$117,967	$2,018,255	$2,620,411
Feb-10	$1,199,000	$169,344	$274,011	$153,762	$1,796,116	$4,416,527
Mar-10	$962,257	$190,208	$367,546	$240,044	$1,760,056	$6,176,583
Apr-10	$353,715	$184,320	$470,470	$368,479	$1,376,983	$7,553,566
May-10	($64,003)	$190,464	$685,676	$1,159,169	$1,971,305	$9,524,872
Jun-10	($292,532)	$184,320	$608,060	$774,541	$1,274,390	$10,799,262
Jul-10	($386,088)	$190,464	$489,347	$446,878	$740,601	$11,539,863
Aug-10	($526,603)	$190,464	$109,987	$28,302	($197,849)	$11,342,014
Sep-10	($775,436)	$184,320	$38,126	($21,704)	($574,693)	$10,767,320
Oct-10	($1,892,959)	$190,464	$33,713	$1,510	($1,667,272)	$9,100,048
Nov-10	($1,969,981)	$184,576	$62,935	($25,160)	($1,747,630)	$7,352,418
Dec-10	($2,360,661)	$190,464	$129,552	$33,210	($2,007,435)	$5,344,983
Jan-11	($2,028,056)	$190,464	$358,952	$390,461	($1,088,178)	$4,256,805
Feb-11	($1,988,465)	$172,032	$273,707	$254,348	($1,288,377)	$2,968,428
Mar-11	($2,328,839)	$190,208	$354,490	$560,010	($1,224,130)	$1,744,297
Apr-11	($2,474,186)	$184,320	$423,551	$532,927	($1,333,388)	$410,909
May-11	($2,658,787)	$190,464	$658,619	$1,331,862	($400,770)	$10,139
Jun-11	($2,618,478)	$184,320	$575,511	$1,051,943	($806,703)	($796,565)

e. Commenter's Issues with the Equivalent Benefits Test

A number of comments questioned whether the market price forecast BPA is using to measure the cost (or benefit) of the Block Contract is too low, thereby underestimating potential costs, in the event BPA would need to make market purchases to support the sales to Alcoa, or the lost opportunity cost associated with selling to Alcoa in lieu of selling that power into what they believe will be a higher priced market (relative to the IP rate). See PPC at 1-2; Canby at 1-2; NRU at 1; PNGC at 2; SUB at 2-6; Snohomish at 2. Some comments suggested that BPA's surplus determination was flawed, and that in developing its market forecast BPA should have relied on forward price curves that guide commodities prices on a short term basis. See e.g., PPC at 4. Others questioned whether BPA's gas price forecast was too low. See e.g., ICNU at 2; Snohomish at 2; and SUB 2-6. A number of parties questioned BPA's loads and resources assumptions, and whether BPA would, in fact, need to make market purchases to support sales to Alcoa under the Block Contract. See e.g., Snohomish at 2-3; Canby at 2.

These issues are addressed below.

1. Loads and Resources Data Used in the Equivalent Benefits Test

Some comments questioned BPA's ability to provide power under the Block Contract without making additional market acquisitions and others suggested that the Equivalent Benefits Test is "faulty" because BPA is not surplus at critical water. See Snohomish at 2-3; Canby at 2. ICNU stated that BPA should demonstrate that it is surplus in each month it intends to sell power to the DSIs before moving forward with any new contract. ICNU at 2.

The following discussion reviews the approach BPA used to establish the loads and resources used in the Equivalent Benefits Test, and demonstrates that they are appropriate to the use of the Equivalent Benefits Test, which is solely to satisfy BPA's conservative interpretation of *PNGC II*.

The FY 2010-2016 net inventory (resources minus loads) values used for the demand shift and avoided transmission and ancillary services expenses analyses were based on using 3,500 simulated load and resource conditions for each month. Deterministic (opposed to probabilistic) data used in these analyses were based on loads and resources data produced at the time of the WP-10 Final Rate Proposal. Variable loads and resources data were derived via running a set of risk simulation models, collectively referred to as RiskSim. Variable net inventory values were computed by the RevSim Model. Both the RevSim and RiskSim models used in this analysis were used in the 2010 Wholesale Power Rate Final Proposal (see Risk Analysis and Mitigation Study and Documentation, WP-10-FS-BPA-04 and 04A).

Two sets of net inventory values reflecting no service to the DSI and DSI service totaling 372 aMW per FY were computed. Results from these two sets of net inventory numbers are identical except for the level of service to the DSI. Net inventory results from these computations reflect PS intent to serve the DSI load out of its energy inventory and meet any power deficits with short-term power purchases.[38] The demand shift analysis and the avoided transmission and ancillary services expenses analysis each encompass the two sets of inventory values.

The demand shift analysis evaluates the value of the price benefit achieved by PS's surplus energy sales when BPA serves the DSI load out of inventory. This price benefit accrues to PS's surplus energy sales because the DSI would not be expected to continue to operate in the absence of a long-term contract with BPA, resulting in lower PNW loads and consequently, lower prices for PS's surplus sales. As such, the demand shift analysis multiplies the prices resulting from the two different PNW loads by the inventory values reflecting DSI service totaling 372 aMW.

The transmission and ancillary services expense analysis evaluates the expense PS avoids when PS purchases fewer transmission and ancillary services. PS avoids these expenses when serving the DSI load out of inventory because the DSI provide their own transmission and ancillary services and our reduced surplus energy sales exceed our portfolio of firm transmission less often. As such, the transmission and ancillary services expenses analysis multiplies the tariff rates for transmission and ancillary services by both sets of inventory values and the expenses avoided are the differences between the two results.

Prior to adjustments that are discussed in this section, the deterministic FY 2010-11 loads and resources data input into the RevSim Model for this analysis are shown in Tables 1-2 (see Attachment B). These are the same data reported in the WP-10 Loads and Resources

[38] BPA owns the output of all energy produced by CGS, which produces approximately 1,150 aMW. CGS is owned and operated by Energy Northwest.

Study, which reflect loads and resources under the current Subscription contracts. See Loads and Resources Study Documentation, WP-10-FS-BPA-01A, pages 10-13. Also, prior to adjustments that are discussed in this section, the deterministic FY 2012-16 loads and resources data input into the RevSim Model for this analysis are shown in Tables 3-7 (see Attachment B). These FY 2012-2016 loads and resources data reflect the forecast under Regional Dialogue contracts and the Tiered Rates Methodology (TRM).

The FY 2010-11 loads and resources data reported in Tables 1-2 (Loads and Resources Study) were modified to reflect serving the planned CGS outage in FY 2011 from monthly inventory, the addition of the Winter Hedging contracts, removing all augmentation purchases, and replacing the DSI load of 402 aMW with two different levels of DSI service (0 and 372 aMW). The energy values associated with the Winter Hedging contracts were added to the data in Tables 1-2, since these energy values are not included in the data from the Loads and Resources Study for reasons discussed in Bliven et al., WP-10-E-BPA-34, pages 2-4. It was assumed in these analyses that all DSI load, to the extent there was any, would be served from inventory.

The loads and resources data reported in Tables 3-7 (see Attachment C) were modified in a similar manner such that, prior to adjusting for the Winter Hedging contracts and serving the planned CGS outages in FY 2013 and FY 2015 from monthly inventory, the PS inventory associated with only serving Tier 1 load under the TRM is in load and resource balance under critical water when there is no service to the DSI. It was assumed in this analysis that, on a forecast basis, there would be no firm energy surpluses or deficits associated with Tier 1 load. The basis for this assumption is that any firm surplus energy would be absorbed via the high water mark (HWM) allocations for Tier 1 power and all load growth (Tier 2 load) would be served by Tier 2 resources.

Given these deterministic FY 2012-16 loads and resources data, the RiskSim models used in the WP-10 rate filing were expanded to simulate risk data through FY 2016 for use in RevSim. The FY 2010-16 surplus and deficit energy values computed in RevSim for the 3,500 monthly games formed the basis for the net inventory values used in both the demand shift analysis and the avoided transmission and ancillary services expense analysis. The demand shift analysis used both the surplus and deficits energy values to account for the impact of surplus energy sales and balancing power purchases in the computations. The avoided transmission and ancillary services expense analysis only used the surplus energy values. This is because PS must pay the transmission and ancillary services expenses to move its surplus energy to the Mid-C delivery point to realize the full market value for its surplus energy sales. In contrast, when power purchases are made to meet energy deficits, the seller is responsible for paying the transmission and ancillary services needed to deliver the power to the BPA transmission system. Once the power is delivered to the BPA transmission system, the requirements or DSI customer has already purchased sufficient transmission and ancillary services to serve its load so there is no additional transmission and ancillary services acquisition expenses to either, BPA, the requirements customer, or the DSI.

2. Forward Price Curve

A number of comments questioned whether BPA's market price forecast is accurate, including in light of certain forward market prices around the time comments were submitted, which they believe indicate that market power prices during the term of the Block Contract will be significantly higher than BPA is forecasting. See, PPC at 1-2; Canby at 1-2; NRU at 1; PNGC at 2; SUB at 3-7; Snohomish at 1-3; ICNU at 3. Some suggested that, rather than develop a market forecast through rate case modeling tools and assessment of market fundamentals, BPA should instead rely more heavily on forward prices curves used in the real time short term markets. PPC asserts that forward prices for power were substantially above what BPA's model predicted they would be in the next few months, and concludes that BPA's reliance on its model is unreasonable without considering actual prices available in the current market. PPC at 6. See also ICNU at 3 (agrees with PPC BPA's calculation of the forecasted net revenues from a market sale of the power is too low).

Likewise, many of these same comments question whether BPA should be basing its revenue analysis of the Block Contract on a market price forecast at all, and suggest instead that BPA should be using, or at a minimum that its forecast is failing to adequately take into account, current forward market prices, which reflect higher prices than contained in BPA's forecast, and which they apparently believe are a better indicator of actual future prices. PPC at 2; Canby at 1; PNGC at 2; SUB at 4. Some of the public customers expressly reiterated the position they have taken elsewhere that the Ninth Circuit's opinion in *PNGC II* requires that BPA demonstrate that its revenues from an IP sale would be expected to be greater than a sale at market, or articulate a similar position. PPC at 1-2 (recent decisions require BPA to demonstrate service to DSI will result in financial benefit to BPA); PNGC at 2 (joining PPC's comments); SUB at 8 (Block Contract benefits only Alcoa and not region "as a whole"); Canby at 2 (BPA must "make money or break even"); NRU at 1 (Block Contract attempts to meet *PNGC II* by demonstrating positive net revenues compared to a market sale).

BPA will respond to the comments above, but reemphasizes that a sale of firm power pursuant to section 5(d) of the Northwest Power Act is not a sale of surplus power that can be sold at market prices. The IP rate is not a market rate, but instead is a cost based rate established pursuant to the directives of section 7(c) of the Act. Further, for the period over which BPA's current firm power rates apply, BPA has already credited those rates with projected secondary sales. *See* Table 4.8.1, WP-10-FS-BPA-05A at 88. Clearly, the market price forecast is an important component in BPA's forecast of expected net revenues under the Block Contract, serving to measure both the cost associated with purchases, if any, required to serve the Alcoa load, or the lost opportunity cost, if any, of selling the power earmarked for sale to Alcoa into the market instead. However, BPA does not agree with the view expressed in a number of comments that current forward market prices are a better indicator of average market prices over the 17-month term of the Block Contract than BPA's market price forecast given BPA does not normally sell or buy forward 17-month strips of power, but rather manages its inventory closer to the actual delivery month. In simplest terms, "forward market prices" are actual prices agreed to between a buyer and seller on any given day for power to be delivered at some time in the future, and therefore represent the price at which two parties are willing to transact *that day* for future delivery; but the market price on that future date of delivery may (and almost certainly will be) either higher or lower. For example, Snohomish commented it received a forward price quote of $59.25 on October 15, 2009, for delivery beginning October 1, 2010, of heavy load hour energy at the Mid-Columbia trading hub. See Snohomish comments in PTP090010 at 2 and Attachment A thereto. By contrast, a "forecast" of market prices seeks to determine what the actual market price will be on a given day (or hour) over a certain future period. Using the preceding example, a market price forecast would project the likely actual market price for delivery of heavy load hour energy at the Mid-Columbia trading hub on October 1, 2010, based on market fundamentals.

While forward market prices reflect the view – at least of those parties entering into forward market contracts – of a fair market price *that day* for power delivered on a future date, forward markets for electricity are increasingly susceptible to the episodic variability and volatility common in commodity markets. This phenomenon is borne out in later electricity forward market prices which dropped substantially from the mid-October forward market prices cited by Snohomish in its earlier comments. In the short passage of time, just three weeks from October 15th to November 6th, the flat average of the forward prices observed by BPA for the 14-month power sale to Port Townsend fell from $46.78 per MWh to $40.30 per MWh and reduced the cost asserted by Snohomish by more than half.[39] Most recently, prices have rebounded to some extent which is attributable to recent cold weather. This contributes to why BPA believes individual forward market price observations can be a volatile indicator and, as a result, a poor tool to employ for longer-term public policy decisions.

As a general matter, while BPA agrees that the forward market is an important benchmark of near-term market prices, it only comes into play if one is willing to lock in a forward purchase or sale for the period quoted. 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.)

In addition to comparing to forward market prices as suggested by PPC and others, BPA has considered the following comparison of the actual historical spot prices for the Mid-C with posted IP rates for FY 2009 and FY 2010. Figure 1 illustrates, by month, whether

[39] Please refer to Attachment H for additional detail on forward prices observed by BPA and BPA's re-creation of the analysis submitted by Snohomish in Attachment A to its October 19, 2009 public comment.

the average of the actual daily spot prices for electricity at Mid-C in each month of calendar year 2009 were above or below the IP rates adopted for FY 2009 and FY 2010.

Figure 1

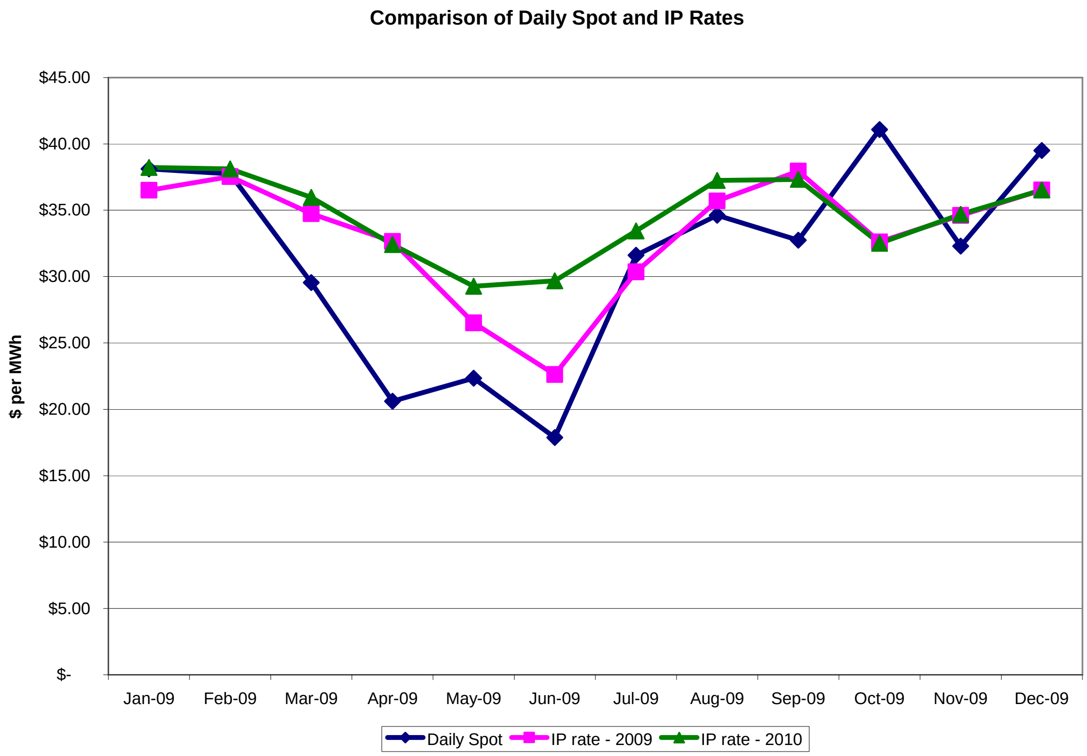
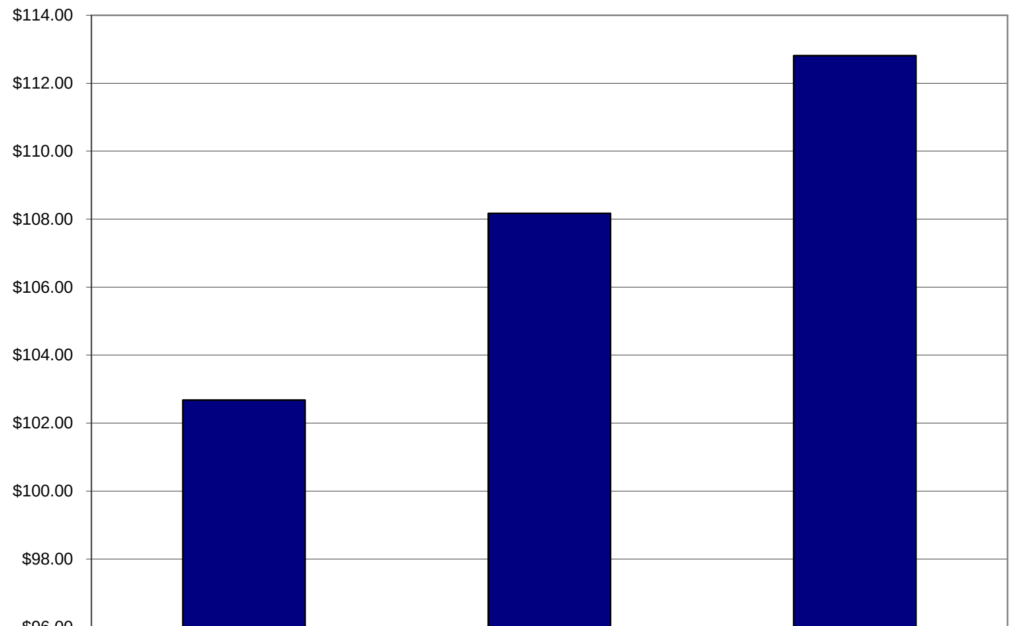


Figure 1 depicts that nine out of the twelve months of calendar year 2009, or seventy-five percent of the time, the monthly average of the daily spot prices was below the IP rate. This is important because BPA is forecasting the average of the daily spot prices at Mid-C, not forward market prices. As such, this demonstrates that it is consistent with recent history to expect that a forecast of the monthly average of the daily spot prices at Mid-C would be below the IP rate in some months. In Figure 2, BPA went on to sum the revenues that would have been received in calendar year 2009 from a 285 aMW sale to the market and a sale of the same amount at the IP rate.

Figure 2

Annual Comparison of Marketing Revenues and IP Revenues



	Daily Spot	IP rate - 2009	IP rate - 2010
Annual revenue ($ mil)	$102.68	$108.17	$112.81

Figure 2 demonstrates that the revenues BPA would have received from the sale at the IP rate in calendar year 2009 would have exceeded by $10 million the revenues BPA would have received from a market sale of the same amount. This provides recent historical evidence to support BPA’s expectation of positive net revenues in the Equivalent Benefits Test and illustrated in Table 4: BPA’s Net Benefit Before Adjustment above. As such, BPA’s market price forecast used in its evaluation of Equivalent Benefits *does not* “blindly adhere to the model’s output,” and *does not overlook* “important realities that BPA must consider if its decision is to be found in accordance with sound business principles.” (PPC in ALC090150 at 6) Quite the contrary, BPA’s evaluation reflects these important realities.

In BPA’s view, the sale under the Block Contract meets its reading of the court’s interpretation in *PNGC II* of “sound business principles” because BPA expects to accrue positive net revenues from the sale compared to its market forecast; in other words, BPA forecasts it will make more money on the transaction compared to selling the power into the short-term market. BPA does not believe either that this is a standard for discretionary sales to the DSIs required by statute, or that the court in *PNGC II* unequivocally held that this is the correct standard. However, if this is, in fact, the legally required standard, then it is met in this case.

However, some parties, including Snohomish and PPC, appear to argue that even this is not enough. These parties appear to take the position that BPA may not make a sale to a DSI at the IP rate even if such sale is forecast to result in positive net revenues compared to forecasted market revenues, if BPA could earn even greater revenues by selling the power into the current forward market. Snohomish at 1-2; PPC at 2.

First, as noted above, BPA does not typically sell its surplus into the forward markets this far in advance or for a term this long. Again, a forward sale means a sale consummated *that day* for delivery sometime in the future. By definition, and especially with respect to a hydro-based system, such sales contain some element of risk. This is because a forward surplus sale would be a firm commitment, and to the extent BPA forecasted surplus did not materialize, it would be required to purchase some or all of that power for delivery to the counterparty. The costs and risks of a BPA firm requirements sale – including the sale under the Block Contract at the IP sale – have been addressed in BPA's rate proceeding. In establishing its firm power rates BPA makes a load and resources forecast which covers its expected sales to regional customer loads – public, cooperative and federal agency customers, investor-owned utilities, and DSIs – and resource needs. In recent years BPA has moved away from making year-long forward sales of its surplus, instead making a majority of its surplus sales into the spot or short-term markets much closer to the time of delivery, when hydrological conditions, load shapes, and other factors impacting BPA's inventory are clearer.

Second, 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.[40] These public customers' view appears to be based on the position that BPA is obligated by statute to maximize revenues through sales of surplus power in order to reduce preference customers' rates to the lowest possible levels. To the contrary, to the extent that BPA finds, consistent with Ninth Circuit case law, that serving DSI load benefits BPA's operations or otherwise promotes its other statutory mandates, then BPA may incur costs to serve DSI load, and allocate such costs to all its base rates, including its preference rates. See *Golden Northwest Aluminum, Inc., v BPA*, 501 F.3d 1037, 1043 (9th Cir. 2007).

It is also worth noting Alcoa has taken the position that BPA is obligated by the regional preference provisions in its enabling statutes to sell available surplus power to any DSI, at the IP rate, before such power can be sold out-of-region at market-based rates, and that *PNGC II* supports its position. See, *e.g.*, Alcoa comments dated August 3, 2009, regarding memorandum of understanding for long-term DSI service proposal, at 2; and Alcoa comments dated September 9, 2009, regarding draft seven-year power sales agreement, at 5 (Attachments D and E). While BPA disagrees with Alcoa's view of the scope of its regional preference right, and its reading of *PNGC II* with respect to that right, it is not unlikely that Alcoa – or perhaps another DSI - would seek to challenge an out-of-region long-term market priced surplus sale made in lieu of selling such power to it at the IP rate. The suggestion that BPA should simply sell into the current forward market the power it would otherwise sell to Alcoa under the Block Contract comes with its own set of litigation risks that would need to be evaluated in the context of putting a dollar value on such a transaction.

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[40] 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).

Finally, ICNU and others commented that BPA's investor-owned utility customers (IOUs) recently filed market price forecasts as part of regulatory filings that show market prices much higher than those forecast by BPA. ICNU at 3; PPC at 2; SUB at 2-5; Snohomish at 1. The IOU forecasts were filed with the Oregon Public Utility Commission in June of 2009 and were probably prepared sometime before that date. A more recent forecast can reasonably be assumed to be more reliable for the purpose of projecting market prices for the 18 month initial period of this contract. Moreover, the filings were made as part of an avoided cost filing, whose purpose is to establish the minimum price that the utility must pay for "Qualifying Facilities" under PURPA. These filings are required to be submitted according to a methodology developed by the Commission for that purpose. From time to time, the methodology is reviewed and modified in a separate proceeding. However, the methodology itself is not reviewed as part of an avoided cost filing. Instead, the avoided cost filing is reviewed only to determine whether it conforms with the established methodology. In other words, there is no direct substantive review of the filing itself. In fact, ICNU and other parties to the relevant avoided cost proceedings sought to open the proceeding to a broader examination of the methodology itself, apparently based on their view that the methodology is flawed. However, the Commission ultimately left that examination to a separate proceeding. In the final analysis, due to the described circumstance, these IOU filings provide little basis for challenging BPA's forecast. See, Oregon Public Utility Commission, Docket No. 1442 and Docket No. 1443, which can be accessed through the Commission's website.

In sum, making a long-term forward surplus sale in lieu of selling 285 aMW to Alcoa, as advocated by some customers in comments, presents its own risks, is inconsistent with BPA's current surplus marketing program approach, and is not legally required, even if it may result in greater revenues compared to revenues under the Block Contract.

3. Gas Price Forecast

Several comments either challenged the gas forecast component of BPA's price forecast covering the period of the Block Contract, or asked BPA to provide additional detail regarding its gas price forecast. Comments submitted by SUB question the validity of the natural gas price forecast component of BPA's electricity market price forecast. SUB at 2-4. SUB believes that increases in gas market spot prices and gas futures prices at the time comments were submitted are evidence that BPA's current gas price forecast is too low, and that even using BPA's gas price forecast from the WP-10 rate case, "the net present value" of the Block Contract to BPA is a negative \$1.8 million. ICNU felt that BPA's gas price forecast was understated based on the forecasts submitted in June of 2009 to the Oregon Public Utility Commission by investor owned utilities (discussed immediately above), which showed a market price forecast higher than BPA's.
BPA stands behind its own 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, as 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, is 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 fiscal third quarter.

To analyze the period covered by the Block Contract, BPA employed the most recent natural gas price forecast it had developed using the same methodology. This is an update to what BPA used in its WP-10 rate proceeding as an input to its forecast of electricity prices and is identical to the natural gas price forecast used in BPA's draft Resource Program released September 30, 2009. BPA's updated natural gas price forecast was completed at the end of July 2009, during BPA's fiscal fourth quarter. With the exception of the fiscal first quarter, BPA typically updates its natural gas and electricity price forecasts during each quarter to support financial reporting.

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 2009-2010, and increase its forecast in 2011. BPA stated in the draft 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.

See draft *Resource Program*, Appendix B: Market Uncertainties, Bonneville Power Administration, September 30, 2009, 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 2009-2010 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, illustrates that BPA's statement in the draft Resource Program that "the production decline lags the decline in demand" remains apparent, 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) record amount of natural gas in storage continues to demonstrate the anticipated "increase in natural gas storage inventories" contemplated in the draft Resource Program.[41] Furthermore, with the majority of the hurricane season now over with no impacts on supply occurring, the reduction made in the fiscal fourth quarter natural gas price forecast appears to remain 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 3 and 4 below, 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, in alphabetical order, typically included in our comparisons are: Cambridge Energy Research Associates (CERA), the United States Department of Energy's Energy Information Administration (EIA), PIRA Energy Group, and Wood Mackenzie.[42] 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 July through October 2009.

[41] In addition, BPA has detailed, with contemporary information from the Energy Information Administration in Attachment H, ("Natural Gas Statistics"), the continued strength of natural gas production despite steep declines in rigs, the continued slow recovery of natural gas demand, and the record amount of natural gas in storage. See also Short-Term Energy Outlooks from the EIA for September and October showing EIA's lower forecasted Henry Hub Spot Price average for 2010 to $4.78 and $5.02 per Mcf respectively [or $4.64 and $4.87 per MMBtu using EIA's conversion of 1 Mcf = 1.031 MMBtu], *Short-term Energy Outlook*, DOE EIA, September 9, 2009, at 1; *Short-Term Energy and Winter Fuels Outlook*, DOE EIA, October 6, 2009, at 3.

[42] With the exception of the EIA, each of these forecasters considers their information to be proprietary. The vintage of each forecast is late September to early October 2009. EIA forecast is from their *Short-Term Energy and Winter Fuels Outlook* released October 6, 2009.

Figure 3: Henry Hub Natural Gas Spot Price Forecasts (vintage September 2009)

Figure 3

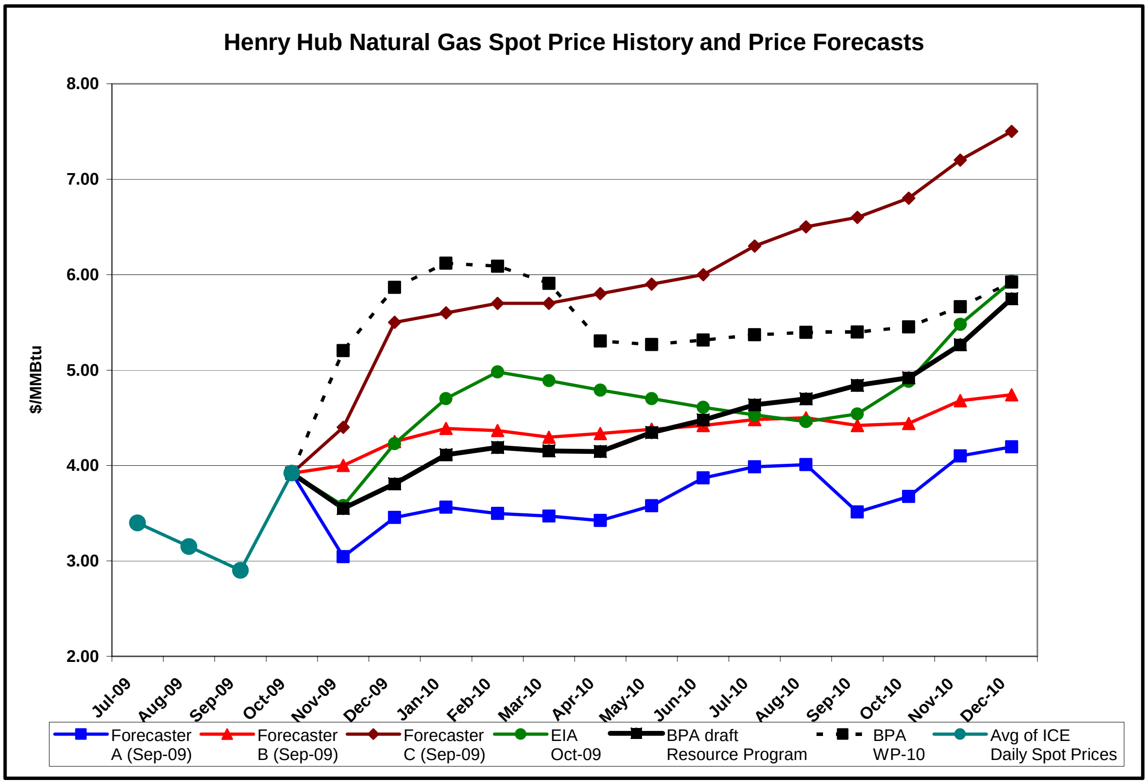
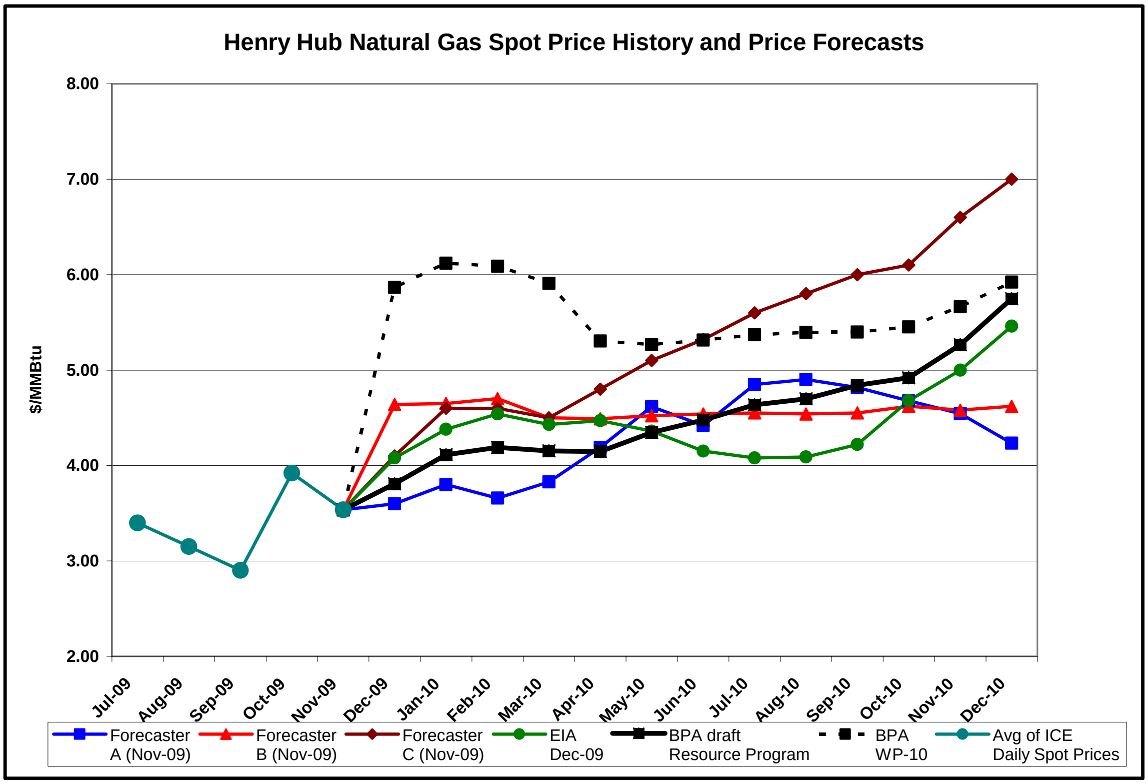


Figure 4: Henry Hub Natural Gas Spot Price Forecasts (vintage November 2009)

Figure 4

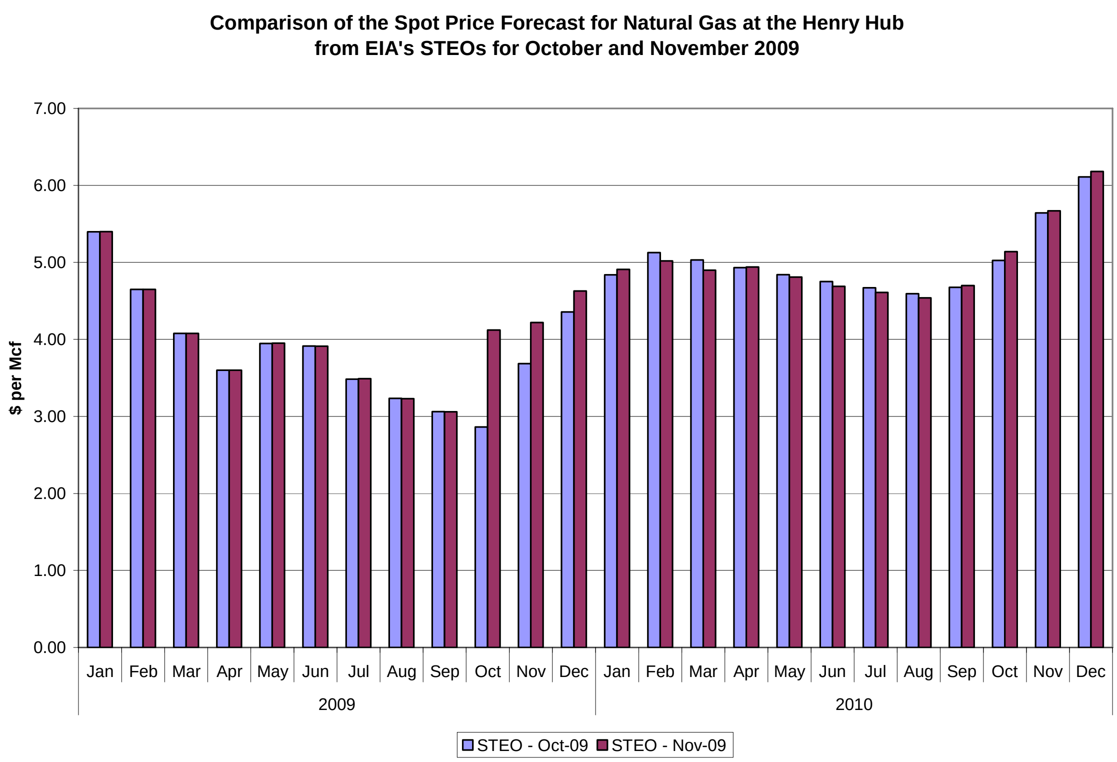


Figures 3 and 4 demonstrate that recent spot market prices for natural gas at the Henry Hub have been in the range of $3 to $4 per MMBtu from July to November 2009. These illustrations also demonstrate that the forecasts of three other industry experts were $4.25 per MMbtu and are now $4.10 per MMBtu or less for December 2009 – the starting month of BPA's equivalent benefits analysis – and both renditions of their forecasts remain lower than $5 per MMBtu through at least October 2010. BPA's updated forecast of spot price for natural gas at the Henry Hub is consistent with this view reflected by these three industry experts. Only one of the four forecasters expected spot prices for natural gas at the Henry Hub to rise above $5 per MMBtu during the winter of 2009-2010 in their September 2009 forecast and in their latest forecast from November 2009 they too expect spot prices for natural gas at the Henry Hub to remain below $5 per MMBtu during the winter of 2009-2010. As a result, BPA believes its updated gas price forecast is reasonable compared to a recent history of Henry Hub spot prices and compared to what other industry experts are expecting.

It is also important to note that BPA may conduct additional evaluation(s) of equivalent benefits in the future. For such future determinations, BPA intends to utilize inputs to the decision process that are as contemporaneous as can reasonably be applied. Such inputs may include updates to BPA's natural gas price forecast, hydroelectric generation forecast, or load forecast. BPA does not believe it would be reasonable to continue using WP-10 rate proceeding inputs when the agency has since updated those inputs.

Finally, SUB asserted in its comments that BPA "used a dated market forecast that does not reflect today's analysis" (SUB at 5) and selectively chose the forecast in BPA's September 2009 resource program as compared to its WP-07 forecast (SUB in PTP090001 at 4) in order to support "an unsound and incomplete forecast for Alcoa Paper…" (SUB in PTP090001 at 2). First, as elaborated above and included in Figure 4, BPA incorporated the EIA forecast from its October 2009 Short-Term Energy Outlook (STEO), which was released on October 6th, to conclude that its updated gas price forecast is reasonable compared to a recent history of Henry Hub spot prices and compared to what other industry experts are expecting – including EIA in its October 2009 forecast. This was the EIA's most current forecast of natural gas available at the time the analysis was produced and remained so when BPA's analysis was posted 7 days later on October 13th. Furthermore, BPA has reviewed the EIA's November 2009 STEO released on November 10, 2009, and EIA largely sustained the forecast of natural gas prices in their October 2009 STEO employed in Figure 4. As illustrated in Figure 5, EIA's most significant change to their forecast was made to the month of October 2009, increasing it from $2.86 per Mcf to $4.12 per Mcf, and their second most significant change was to November 2009, increasing it from $3.69 per Mcf to $4.22 per Mcf.

Figure 5: Comparison of Natural Gas Forecasts from EIA's STEOs



The entirety of October 2009 and 14 days in November 2009 are not within the term of the Block Contract and thus are not germane to BPA's analysis. Furthermore, the historical observations that BPA has incorporated 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 July *through October 2009*. BPA has not incorporated EIA's forecasted value for October 2009 as inferred by SUB.

Regarding the remaining months beginning with December 2009 and extending through December 2010, the EIA went on to say:

> Although [spot] prices [for natural gas at the Henry Hub] have more than doubled since reaching a low of $1.83 per Mcf on September 4, EIA expects any further price run-up to be limited through the remainder of the year. High storage levels and resilient domestic production are expected to keep prices around $5 per Mcf in the coming months, even as space-heating demand increases and economic conditions improve. Beyond the winter, limited demand growth constrains price increases through the forecast. The projected Henry Hub spot price averages $4.03 per Mcf in 2009 and $5.01 per Mcf in 2010.

Short-Term Energy Outlook – November 2009, at 6.

The effect of EIA's changes over the term of the Block Contract beginning November 15, 2009, and extending through December 31, 2010, increased their average forecast for the period from $4.92 per Mcf to $4.95 per Mcf, or a change of less than one percent (1%). As a result, BPA believes this sustains its earlier conclusion that BPA's updated natural gas price forecast is reasonable compared to a recent history of Henry Hub spot prices and compared to what other industry experts, including EIA, are expecting.

In summary, BPA has utilized the most recent forecast of Henry Hub natural gas spot prices that BPA has performed. BPA's updated natural gas price forecast also reflects a more contemporary understanding of natural gas market fundamentals than the WP-10 natural gas price forecast. Furthermore, BPA's updated natural gas price forecast is reasonable when compared with the recent history of spot market prices for natural gas at the Henry Hub and the natural gas price forecasts of other industry experts. Moreover, BPA has reviewed EIA's most current STEO and addressed the risk of prices deviating from expectations. Therefore, BPA believes the updates made to its forecast of Henry Hub natural gas spot prices and its use as an input to the Aurora model utilized in this analysis are reasonable.

4. Risks are Addressed in BPA's Equivalent Benefits Test

SUB and Canby each commented that BPA has inadequately addressed certain risks inherent in the sale to Alcoa, in particular the risk that market prices will trend significantly higher than BPA's forecast, including in the event a threatened drier than average water year materializes, leading to costs that have not been accounted for by BPA. SUB at 6-7; Canby at 2. Specifically, SUB asserts that BPA has "failed to address risk" and describes scenarios, mainly related to market prices and the availability of surplus on BPA's system, under which BPA may incur costs to serve Alcoa. SUB at 6-7). Similarly, PNGC argues that if market prices turn out to be higher than BPA is forecasting, which PNGC believes will be the case, then BPA is underestimating the cost to serve Alcoa under the Block Contract. PNGC at 2.

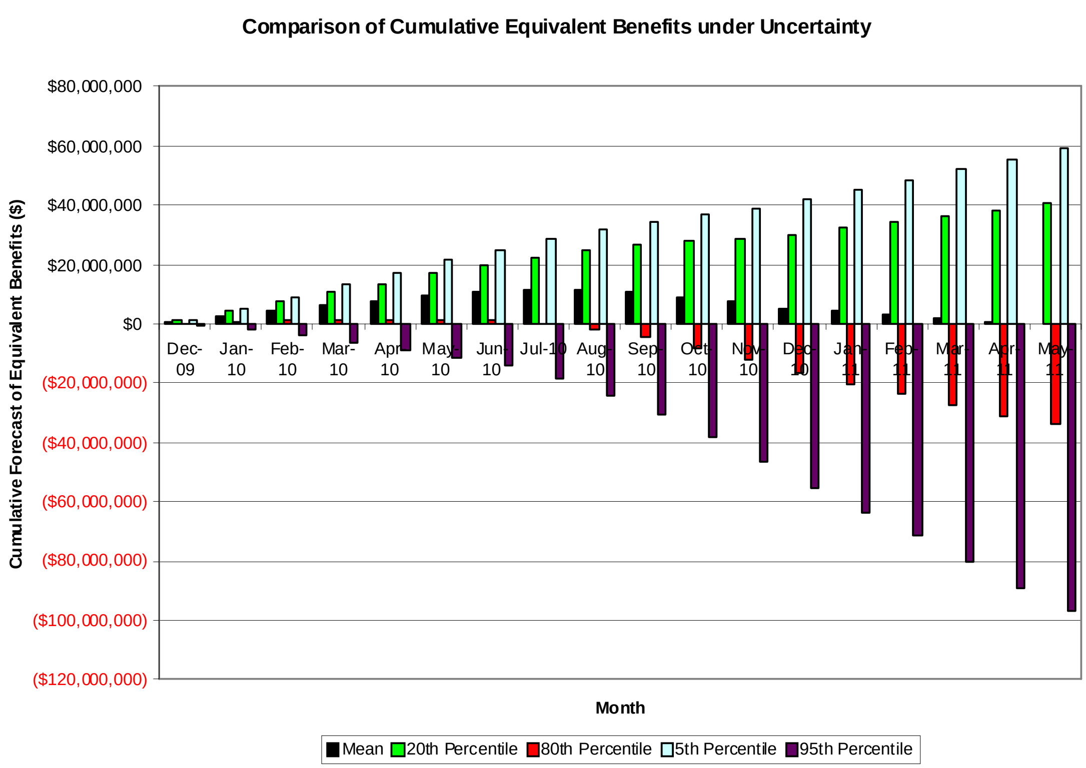
PPC's also argues that BPA is at risk that power prices could change from BPA's forecasts, and that if BPA's forecast is incorrect the costs of the transaction could easily turn out to outweigh any calculated benefits. PPC at 2.

In BPA's view, there are two primary elements of risk in this transaction. First, is the risk of market prices for electricity deviating from the prices forecast by BPA during the Initial Period. The second primary element of risk is the possibility of Alcoa curtailing. This is less of an issue during the Initial Period of the Block Contract because BPA anticipates serving Alcoa from the surplus energy inventory expected under most water conditions, as discussed above (see Loads and Resources section).

(i) Market Price Risk

BPA examined the Block Contract both in isolation and more broadly in consideration of BPA's other risk factors. In examining the Initial Period of the Block Contract and the effects on the Equivalent Benefits Test 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.

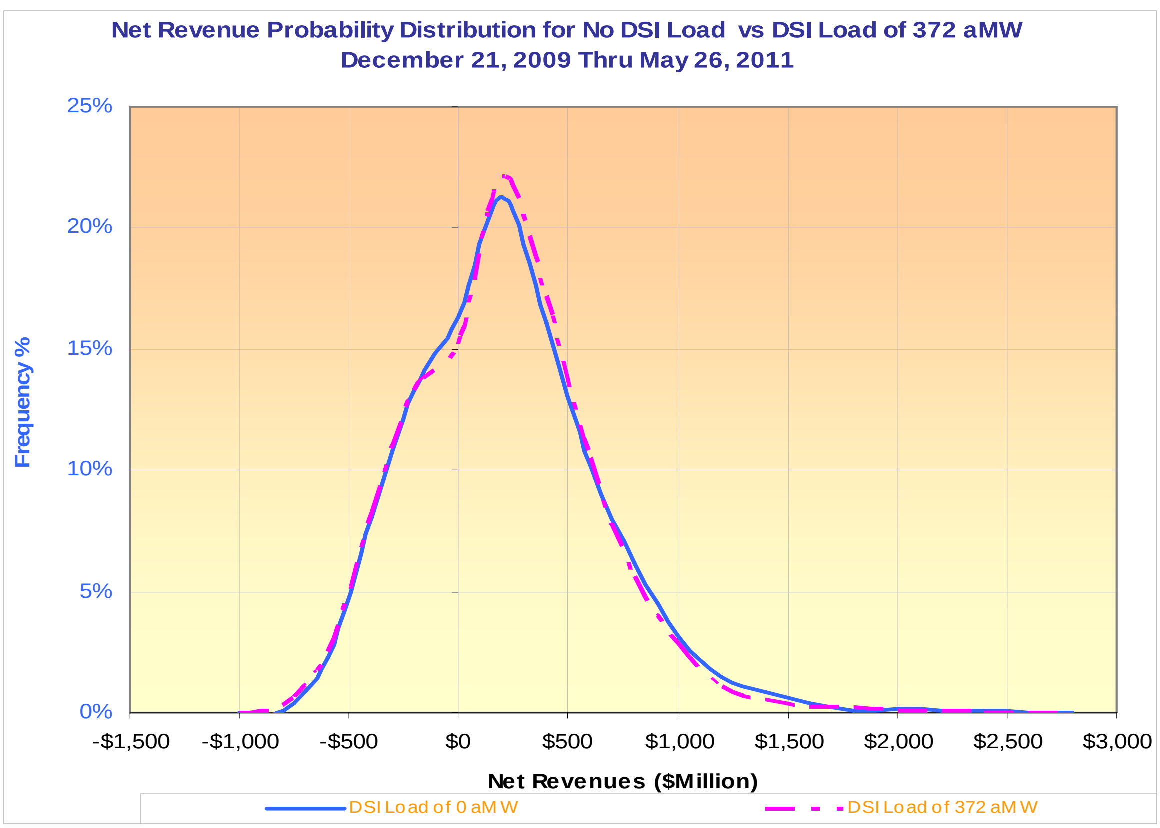
Figure 4: Comparison of Cumulative Equivalent Benefits under Uncertainty



If market prices for electricity are less than expected, BPA is better off financially serving Alcoa than selling this power on the wholesale electricity market. This is reflected in Figure 4 above for the 5th and 20th percentiles. Conversely, if market prices for electricity are higher than expected, the economics of the Equivalent Benefits deteriorate resulting in BPA being relatively worse off on this transaction alone. This is reflected in Figure 4 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 the DSI sale under higher prices than forecast is associated with higher surplus energy revenues.

Regarding the financial risk that market prices deviate from the average of BPA's price forecast more broadly, and they will, 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 considers 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, as demonstrated in Graph 1 below, is that the probability distributions of BPA's net revenues, one of its broadest measures of financial impact, are not materially different whether it serves 372 aMW of DSI load or does not serve any DSI load during the Initial Period.

Graph 1



If there is a Second Period, it would be up to BPA to prudently manage any power purchases and address the financial risks it perceives for all of its load obligations, including Alcoa's Intalco Plant, in its future rate proceedings. All risk mitigation measures undertaken will be consistent with its then current Financial Risk Policy and the allocation of the cost and risks will be undertaken in future 7(i) proceeding(s).

(ii) Curtailment Risk

Regarding the risk of curtailment, the net revenue risk analyses above indicate that BPA financial risk exposure is not materially different depending on whether or not the DSI operate in the Initial Period. Furthermore, BPA does not expect Alcoa will curtail the Intalco Plant once at least 320 aMW of service is made available to it at the IP rate, which is provided in the Block Contract, because Alcoa requested an increase in firm power from 285 aMW to 320 aMW and Alcoa has consistently argued 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." *See* Alcoa's December 15th letter requesting 320 aMW of firm power attached to this Record of Decision, Alcoa in DSL090057 at 5, and Alcoa in DCA090233 at 1. Conversely, if Alcoa did shut the Intalco plant down after signing the Block Contract, 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, as discussed in detail in the following subsection, 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.

For the foregoing reasons, BPA believes it has adequately addressed the risks associated with the Block Contract. BPA has prudently accounted 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 transaction.

PPC also argues that the Block Contract is predicated on the assumption that BPA will incur a loss. PPC at 3. BPA does not believe that PPC's statement is accurate. BPA has determined that, for first seventeen months (the Initial Period) of its proposed term, the contract will provide benefits that equal or exceed the cost of providing service. That is not operating at a loss. Any additional service for the Second Period is contingent on application of whatever test the court ultimately requires. However, it is clear that the contingent period of the contract (i.e., the so-called Second Period), or any Transition Period, will only trigger upon BPA's finding that such service comports with both whatever analysis the court requires, as well satisfaction of the Cost Caps.

PPC also argues that BPA would not, in the ordinary course of business, enter into this transaction. PPC at 4. The basis for this conclusion by PPC is unclear. Dealing with the issue of providing service to DSI load has been part of the ordinary course of BPA's business for more than half a century. It does not follow that, simply because such service is now discretionary, it should be deemed, *ipso facto*, outside the ordinary course of BPA's business or mission. There is no indication, that in making DSI service discretionary, Congress was directing the Administrator to simply cast the DSIs aside and be done with them. To the contrary, by preserving a special rate for service (the section 7(c) rate), and requiring the continuing provision of reserves, Congress appears to have contemplated that BPA might well continue to serve DSI load in the ordinary course of business.

Moreover, PPC is comparing apples to oranges. PPC equates the business considerations regarding a DSI sale with those relevant to a market sale of surplus power. But that is not the case. As discussed earlier, DSI sales are not surplus sales. They are sales of industrial firm power. BPA does not apply the same principles to such a sale that it would normally apply to its surplus sales. One of the primary purposes of the Northwest Power Act is to assure the Pacific Northwest of an adequate, efficient, economical and reliable power supply. DSI customers have been, and are, an important part of the Northwest's economy, and as such are included in the purpose of the Northwest Power Act just noted. Similarly, Congress enacted the Regional Preference Act, 16.U.S.C. 837 *et seq*. "to guarantee electric consumers in the Pacific Northwest first call on" Federal hydropower, and in section 9(c) of the Northwest Power Act extended that protection to all BPA power, 16 U.S.C. 839f(c). Both an IP sale to a DSI and a surplus sale into the wholesale market are transactions that occur in the ordinary course of BPA's business, but each has its own unique characteristics and so the considerations relevant to each are not the same.

Nonetheless, PPC asserts that *PNGC II* requires BPA to compare DSI service to other options for disposing of the power, and that BPA should be evaluating any DSI sale to the other options available for disposing of that power, which in this case is a surplus sale into the wholesale market. PPC at 4.

BPA does not agree with PPC's interpretation of *PNGC II*, nor does it operate based on the "business procedures" that PPC would seek to impose. BPA's consideration of making a sale of industrial firm power at the IP rate is, for the Initial Period, whether the benefits of such a sale will equal of exceed the cost. In reaching that conclusion, BPA has considered potential lost opportunity costs based on the alternative of marketing the power as surplus into the real time markets, even though it is not clear that such an analysis is absolutely required. See discussion at section V. BPA has taken a cautious approach to its determination, based on its reading of the *PNGC II* opinion, even though BPA believes that less stringent approaches are at least arguable, even if not specifically articulated by the opinion. Moreover, PPC fails to recognize the inherent risks of under-recovery that could result from selling such power in the typically unpredictable real time markets, as opposed to locking in a revenue stream that BPA forecasts will result in positive net benefits. In short, *PNGC II* does not require the "comparative" analysis prescribed by PPC, but even if it did, BPA would still elect to provide service to Alcoa.

In addition, PPC's comment fails to recognize, in the first instance, that BPA is not a profit-making enterprise, but rather a government agency charged with balancing the interests of all regional consumers and maintaining the financial integrity of the agency.

BPA's primary responsibility is to meet its financial obligations and repay the Federal investment in the system over a reasonable period of time. In this instance, while an incomplete subset of BPA's analysis shows a potential lost opportunity cost of $17,000,000, it must be recognized that realization of such an amount through market sales is not guaranteed, but is subject to typical market risks. By contrast, the IP rate transaction with Alcoa guarantees a revenue stream that assures no significant adverse financial impacts will occur and the rates of BPA's customers will not be jeopardized. Additionally, BPA has identified and developed a value for tangible benefits derived by BPA through the transaction, which more than offset the lost opportunity costs.

For its part, WPAG characterizes the Block Contract as a subsidy by BPA to Alcoa. WPAG in DCA09 at 3. A subsidy would occur if BPA were selling the power at less than the IP rate, but that is not the case here. Given the specific rate protections afforded preference and DSI customers in the Northwest Power Act, there is no more basis to say DSI rates are subsidized than to say PF rates are subsidized. WPAG seems to suggest that BPA must attempt to maximize its "profits" for the financial benefit of preference customers by selling power on the market rather than selling to Alcoa at the IP rate. BPA has conducted extensive analysis regarding the merits of both scenarios, and has determined that there is less risk associated with a sale to Alcoa as opposed to accepting the inherent risks associated with the vagaries of the open commodities market. WPAG has provided no analysis that would cause BPA to believe it is unreasonable to provide service to Alcoa.

Further, in characterizing the transaction as a "subsidy," WPAG suggests that preference customers would have an entitlement to the proceeds of any secondary sales of surplus on the open market. However, surplus sales and their associated secondary revenues only occur once BPA's net requirement obligations are met. Section 5(f) of the Northwest Power Act is explicit that requirements sales come before surplus sales. 16 U.S.C. § 839c(f). As thoroughly discussed in a response by the Department of Energy's General Counsel to a Congressional inquiry, preference customers cannot legitimately claim an unreserved statutory entitlement to all surplus sales revenues.[43] Neither is the Administrator required to take the risk of making market sales, in lieu of generating revenues through the IP rate, a rate which generates significantly higher revenues per megawatt than the PF-preference rate. In short, the Administrator views service at the IP rate for the Initial Period of the contract as being consistent with recent Ninth Circuit opinion and his statutory mandates, such as to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply.

[43] See letter of David H. Hill, former DOE General Counsel, dated June 23, 2006, to Senator Maria Cantwell, entitled "Legal Authority for Administratively Pursuing the President's Budget Proposal That BPA Pre-pay Bonds When BPA's Annual Net Secondary Power Sales Revenues Exceed $500 Million.".

5. Examination of the Correlation between LME Aluminum Prices and Dow Jones Mid-Columbia Spot Prices

PPC commented that BPA's low forecasts for both aluminum and power prices may indicate there is "a correlation between a DSI's decision to curtail and a low market in which BPA would have to resell such power." PPC at 2.

Provided below is an analysis of the cross-correlation between two sets of contiguous historical price data over various durations in time. One of the sets of data is the three-month aluminum price at the London Metal Exchange and the other set of data is the price of electricity sold on the Dow Jones for the Mid-Columbia hub. To perform this analysis, BPA used historical price data from January of 1997 through October of 2009 and subdivided the data into one and a half, two, five, and seven year periods. The cross-correlation between the two sets of price data over the entire period is 0.0826, which is very weak and not materially different than zero. However, as reported in Tables 2-4 below, the cross correlations were found to vary dramatically depending on the time-contiguous subset of the period that is chosen.

By computing the cross correlations between LME aluminum prices and Dow Jones Mid-C electricity prices over different combinations of contiguous years and lengths of time, an evaluation can be made regarding how consistent or inconsistent are the correlations between these two sets of prices. By analyzing the historical record of price data, it can be observed that the correlation between these two sets of prices very much depends on which years are selected. This can be observed by comparing the very dramatic differences in the correlation values reported in Table 2 over eighteen month periods, which is the approximate length of the Initial Period of the Block Contract, and over two year periods.

Table 2: Two Year and Eighteen Month Correlations Between LME Aluminum Price and Dow Jones Mid-C Electricity Prices

Years	Two Year Correlation	Eighteen Month Correlation
1997 to 1998	-0.676	-0.004
1998 to 1999	0.190	-0.512
1999 to 2000	0.289	0.739
2000 to 2001	0.315	-0.135
2001 to 2002	0.889	0.890
2002 to 2003	0.450	0.182
2003 to 2004	0.355	0.018
2004 to 2005	0.728	0.267
2005 to 2006	-0.113	0.777
2006 to 2007	-0.236	-0.200
2007 to 2008	0.064	-0.574

2008 to 2009 [44]	0.675	0.194

Results reported in Table 3 for the five-year correlations and Table 4 for the seven-year correlations indicate that the correlations for these longer time periods are less variable than over two years periods, however, they are still very variable. Also, comparisons between the results in Tables 3 and 4 indicate that the impact of longer periods of time does not always reduce the observed spread in correlation values.

Table 3: Five Year Correlations Between LME Aluminum Price and Dow Jones Mid-C Electricity Prices

Years	Correlation
1997 to 2001	0.206
1998 to 2002	0.466
1999 to 2003	0.456
2000 to 2004	0.184
2001 to 2005	0.157
2002 to 2006	0.557
2003 to 2007	0.352
2004 to 2008	0.229
2005 to 2009 [45]	0.395

Table 4: Seven Year Correlations Between LME Aluminum Price and Dow Jones Mid-C Electricity Prices

Years	Correlation
1997 to 2003	0.252
1998 to 2004	0.255
1999 to 2005	0.160
2000 to 2006	-0.011
2001 to 2007	0.023
2002 to 2008	0.591
2003 to 2009 [46]	0.470

We can see from these figures that there is not a consistent cross-correlation between these time series. Additionally, the time periods examined are clearly not independent observations. Furthermore the number of observations for inference is small for both the two and five-year period lengths.

[44] Two year figure through October of 2009.

[45] Figure through October of 2009.

[46] Figure through October of 2009.

The relationship between the LME aluminum price and the Dow Jones Mid-C electricity price has not shown a consistent or stable enough relationship historically to allow for the basic inference drawn by PPC.

6. Avoided Transmission and Ancillary Services Expenses

SUB questioned BPA's inclusion of avoided transmission and ancillary services expenses as a benefit to BPA in the Equivalent Benefits Test. SUB at 9. BPA's explanation of the nature of this benefit is described above in section V(d). SUB questions BPA's analysis of the transmission and ancillary services expenses avoided by selling power to the DSIs out of its inventory as opposed to selling the same amount of power as surplus on the wholesale electricity market. *Id*. That is not what BPA forecasts to occur with service to Alcoa in the Initial Period.

Though not relevant to the analysis, SUB's question reflects a misunderstanding of the transaction that they described. BPA does not provide service to Alcoa on BPA's transmission inventory. BPA provides power to Alcoa from the Federal System. When BPA makes a market purchase, it may use that power to serve any of its obligations on the system. If BPA Power Service elects to use the market purchase to serve its obligation to Alcoa, BPA Power Service has the contractual right to supply power to Alcoa at non-federal point of integration where it receives the market purchase. Alcoa can use the firm Point to Point transmission it holds to move power from the FCRPS by redirecting that long term firm transmission to the non-federal point of integration. Alcoa's long term firm Point to Point transmission agreement is a type of firm transmission that can be redirected under the Transmission Service Business Practices. 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 the 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. BPA expects these congestion costs to be de minimus.

7. Demand Shift

WPAG asserts that the "Demand shift" calculation is nothing more than an ad hoc adjustment to make contracts appear more economic. WPAG at 4. For its part, PPC states there can in fact be no demand shift through BPA's selling of power to Alcoa since Alcoa has already secured power in the market which it will have to unload into the market in order to take BPA's power. PPC at 3. PPC finds it hard to believe that Alcoa's contractual right to do things it already has the right to do would make the difference between whether Alcoa operates or not. Id. at 5. PPC also contends that it is 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 facility. Id. SUB and ICNU echo these comments. SUB at 10; ICNU at 4.

First, BPA has clarified its assumption about plant operation. Upon execution of a contract with BPA, Alcoa's Intalco Plant will operate. After the contract is executed, Alcoa's Intalco Plant operation will be made based primarily on the prices for its output which are independent of power prices.

As indicated earlier, WPAG highlighted an acknowledged fact that if Alcoa, or other DSIs, are served by a third-party electric power supplier, their load will exist and the market price benefit will be received by BPA independent of whether BPA sold power to Alcoa or other DSIs. Other parties argued to similar effect. In BPA's view, Alcoa and other DSIs will not continue to operate unless they can secure a power sale at the IP rate from BPA. Subject to this view, the value derived from the demand shift benefit is dependent on BPA's decision to serve the DSI load.

PPC and ICNU argue that there can be no demand shift through BPA's selling of power to Alcoa. These parties take the position that since Alcoa has secured power from a third party for the initial period the proposed contract covers, Alcoa will need to sell its third party power into the market in order to take BPA's power. The parties argue that precisely the same amount of power will be available in the market whether BPA sells the power to Alcoa or not. BPA disagrees.

BPA's analysis is a demand side analysis. The resale of power into the market is not the driver of the price reduction. The loss of firm load is the driver of the price reduction. All else equal, a DSI plant shutdown will reduce the market demand for electricity. For every month of the analysis, the amount of demand will be less than it would otherwise be. Therefore, a reduced demand for energy will reduce the market-clearing price for energy, because a lower variable cost unit will supply the unit of electricity that creates supply and demand equilibrium.

The supply for the market load comes from a fixed set of resources. These resources are the electric power plants that are modeled in AURORA. The model uses the load forecast and the specification of plant cost components, physical plant characteristics and operating constraints for each of the supply-side generating resources to build an economic dispatch for each of the market zones in the model. Resources are dispatched according to variable cost, subject to operating constraints, until energy demand is met in each zone of the model.

Selling the third party power into the market will not change the fact that the market demand for electricity in the PNW is less than it would have been if the DSI plant was operating. Selling the third party power into the market will only establish an energy supplier for the pre-established energy demand. The third party power is one of many transactions that will establish the resources that will meet load in the PNW or an adjacent market.

ICNU also argues that if BPA assumes Alcoa will operate with a power sale at the IP rate, then Alcoa will operate with the power that is has secured from a third party for the initial period. ICNU at 4. ICNU argues that if BPA accurately forecasts market prices, Alcoa should be financially indifferent to an operation decision based on its current third party power contract or a power purchase from BPA plus the loss from selling its third party power at the market price in BPA's Mid-C price forecast. BPA disagrees with ICNU's conclusions. BPA has previously expressed its view that Alcoa and other DSIs will not continue to operate unless they can secure a power sale at the IP rate from BPA. Furthermore, ICNU erroneously applies BPA's Mid-C market price forecast as Alcoa's basis for making operating decisions. ICNU's assertion that Alcoa would be financially indifferent is true only if Alcoa manages its power supply portfolio on a short-term basis that is similar to the method that BPA manages its inventory, which it does not, given its fundamentally different interests. Alcoa's current power purchase from a third-party, and its desire for a long-term contract, are strong indicators that Alcoa would not manage its power supply in a manner that is similar to BPA's inventory management.

8. Puget Sound Area Northern Intertie ("PSANI")

PPC argued BPA should not count the "demand shift" due to transmission problems that it believes are attributable to Alcoa, and 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 facility. PPC at 5. Snohomish argues that a physical delivery of power from the Federal system to Alcoa, rather than a secondary sale of surplus from the Federal System to the Mid-Columbia market hub, increases congestion through the Puget Sound Area and the likelihood of additional PSANI curtailments. Snohomish at 3.

The PSANI area consists of the interconnected electric systems, including BPA's network transmission facilities, in the Puget Sound area and BPA's Northern Intertie facilities. BPA monitors the system operating limits (SOL) of the Northern Intertie (NI) facilities in the south to north direction to determine if the NI SOL levels will be sufficient for the transaction commitments that affect those facilities for the next hour. The transactions affecting the NI SOL include south to north scheduled deliveries to all Puget Sound Area customers and scheduled deliveries over the NI. The measures that are monitored are identified as the PSANI mitigation or congestion measures. A PSANI congestion problem is a south to north problem that arises when multiple factors interact at the same time to affect the NI SOL in this direction. These factors include how planned or unplanned facility outages; temperature; the forecasted generation patterns in Puget Sound Area, the forecasted load in the Puget Sound Area, and all of the scheduled deliveries in the south to north direction to serve the load in the area and deliveries to Canada, taking into account any north to south deliveries (i.e., counterflows) from Canada. The load level at Aloca's Intalco Alcoa plant, by itself, is not the source of the problem.

All deliveries of power in a south to north direction contribute to the congestion problems in the area, including south to north deliveries to serve Alcoa's load. If Alcoa or any other load in the area acquires power from the north, in most cases those counterflows help to alleviate any PSANI congestion problems. However, if Alcoa does not operate the plant, that by itself is not likely to be sufficient mitigation to the area congestion.

BPA would continue to be obligated to manage the south to north deliveries to any load in the area including Snohomish, Seattle, BPA's transfer customers, Puget or deliveries to Canada. If the Alcoa load disappears, there are others in the transmission queue that are seeking rights to the transmission capacity that presently serves the Alcoa load. Further, Alcoa holds those transmission rights and may permanently transfer them to any eligible willing buyer. If any transmission capability reverts to BPA and is available, BPA must release it to the market under its open access transmission service policies. Since multiple factors contribute to the problem, and the congestion is specific to all of the conditions that apply at the time, BPA cannot definitively say that if Alcoa did not operate the plant, the congestion problem would disappear.

The PSANI congestion issues are not limited to whether the Alcoa plant is operating. As described above, many factors contribute to the congestion. While no new transmission rights are required to deliver the power made available under the Block Contract to Alcoa's load, BPA expects that ALCOA will increase slightly its south to north scheduled deliveries under its existing transmission rights above the scheduled delivery amounts observed in Calendar Year 2009. This is true regardless of whether the power is sourced from the FBS inventory either directly or as a secondary sale of surplus power from the FBS through the Mid-Columbia market hub. However, the conditions that contribute to the PSANI congestion are not static and must be subjected to detailed technical studies and analyses to state with more certainty what the pertinent contributing factors are at the time.

Management of the PSANI mitigation measures is labor intensive, and requires the involvement of multiple staff from several of BPA's transmission organizations. As described above, however, Alcoa's continued operation and the associated transmission arrangements and scheduled deliveries to support those operations are just some of the inputs to be considered. Thus, the costs associated with management of the PSANI mitigation measures will be incurred whether ALCOA continues to operate or not.

BPA has worked closely with Puget Sound Energy, Snohomish PUD and Seattle City Light ("Puget Sound Area customers") on issues contributing congestion in the PSANI area, including coordinating planned maintenance outages to minimize impacts, and undertaking efforts to encourage the Puget Sound Area customers to increase generation in the area during periods of congestion. BPA also invested in transmission reinforcements in the area and system automation, and has conducted training for operations and technical staff of the Puget Sound Area customers to ensure all entities fully understand implementation and operation of the PSANI curtailment procedures.

BPA is continuing to work with the Puget Sound Area customers to increase the accuracy of the inputs used by the curtailment tool and to come up with plans of service for the interconnected systems that will help to meet the future service needs. BPA is also participating with the parties in the Puget Sound Area Study Team which is specifically focused on service to this area. Since BPA manages PSANI congestion problems through curtailment protocols, there is no direct financial cost to BPA and hence it does not affect BPA's Equivalent Benefits Test Analysis.

In summary, BPA has addressed concerns raised in this section e by commenters and has decided that the Equivalent Benefits Test is based on solid analytics and is a reasonable, though conservative, approach to determining if the Alcoa Block Contract is consistent with sound business principles.

f. Intangible benefits that accrue or may accrue to BPA

BPA believes its forecast of positive net revenues is probably conservative, inasmuch as the sale to Alcoa encompasses certain additional intangible and qualitative benefits to BPA's operations. These benefits include, for example: a) Alcoa's waiver of any claim to money or any other remedy with respect to the Original Contract BPA;[47] b) Alcoa's agreements not to request surplus firm power from BPA or challenge BPA's sales of surplus firm power to other customers;[48] and c) potential for BPA's sales to the DSIs at the IP rate to mitigate the risk that BPA's surplus sales may be impacted by periods of negative pricing (i.e., suppliers would be paying counterparties to take their power) that are the result of rational economic behavior by suppliers of generation but not sufficiently addressed by models currently available to forecast prices of electric power.[49] They also include value that may be ascribed to the historical relationship BPA has had with Alcoa and the value that Alcoa may yet bring in the future as BPA and the power industry continue to evolve in the face of changing regulatory regimes, technological advancements, and fluctuating consumer behaviors.

However, adjustments for these benefits to BPA are not included or relied upon here because they are more qualitative than quantitative at this time and therefore do not presently affect BPA's decision to offer the Block Contract. Adjustments for these or other benefits may affect the tenor and/or megawatt amount of future sales. Nonetheless, in light of comments, BPA believes it is important to provide some discussion here of these prospective benefits.

Waiver of Claims

Alcoa's waiver of any claim to money or any other remedy with respect to the Original Contract could be important with respect to disposition of the Court's remand to BPA in *PNGC I* and *PNGC II* with respect to the application of the damage waiver and severability provisions of that contract.. Alcoa has asserted (though has not formally filed)a $190 million claim against BPA in connection with the Original Contract, based on its reading of *PNGC I*. Pursuant to the waiver provided by Alcoa in the Block Contract, in the event BPA issues a final decision on remand that no money is owed by either party to the other, and that decision, if challenged in a petition for review, is

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[47]Section 23.2.

[48] Section 25.2.

[49] *Frequent negative power prices in the West region of ERCOT result from wasteful renewable power subsidies*, Knowledge Problem, November 20, 2008, http://knowledgeproblem.com/2008/11/20/frequent_negati/

sustained by the Ninth Circuit, then Alco agrees not to pursue its claim. See Block Contract section 23.2. While it appears to BPA that Alcoa's claim that it was provided a legally insufficient amount of benefits under the Original Contract, as amended, probably has little merit, especially in light of the Court's opinion in *PNGC II*, Alcoa's waiver, if applied, would spare BPA the time and expense associated with litigating Alcoa's claim.

Alcoa Agrees not to Challenge Surplus Sales

Alcoa also agreed in section 25.2 of the Block Contract, subject to certain conditions, that it will not request any surplus firm power from BPA, will not challenge any proposed or actual BPA sales of surplus firm power, and will not challenge any BPA rates adopted by BPA for the sales of surplus power. Alcoa has taken the position in a number of different forums, including in briefs filed with the Ninth Circuit, that pursuant to the Pacific Northwest Consumer Power Preference Act (16 U.S.C. §§ 837, *et seq*.) (Preference Act) it is entitled to have its loads served with BPA surplus power, at BPA's lowest cost rate, prior to BPA selling such surplus power outside the Pacific Northwest. Alcoa has indicated that it believes this position was endorsed by the Court in *PNGC I*. BPA disagrees with Alcoa's interpretation of BPA's obligations under the Preference Act, and believes Ninth Circuit case law supports BPA's long-held position that the Preference Act provides only that the customers defined therein are given a priority with respect to the availability of BPA's surplus power, and not preferential pricing. See e.g., *Kaiser Aluminum & Chemical Corp. v. BPA*, 261 F.3d 843 (9th Cir. 2001). Nevertheless, as with the waiver of claims with respect to the Original Contract, Alcoa's waiver, if applied, would spare BPA the time and expense associated with litigating any Alcoa petitions for review with respect to BPA's surplus sales program. The waiver has the additional benefit of eliminating any possible hesitation a potential counterparty may have to executing a surplus power transaction with BPA based on the threat that the contract may be the subject of litigation in the Ninth Circuit.

Negative Pricing

Presently, the power industry is experiencing dramatic changes, especially with respect to facilitating the development and integration of wind resources. BPA has successfully integrated upward of 2000 MW of wind capacity on the Federal power system. However, successfully utilizing wind resources presents major challenges. In addition to the reliability problems inherent in the unpredictable nature of wind, there is a significant potential for certain market aberrations when the resource, such as wind resources, is heavily subsidized. In some areas, as shown below, the power market is dealing with "negative pricing" issues attributable largely to the integration of wind resources. Negative pricing, a phenomenon associated with certain renewable resources that receive tax of other monetary incentives associated with their output, occurs when, in certain market situations, the value of those incentives exceed the cost to a resource owner of paying counterparties to take its power.

For the past decade or so, wind projects have been eligible to receive production tax credits (PTCs) that have increased annually to their current level of $21.00/MW/Hr (2008 value). A wind project is eligible to receive PTCs for ten years from the date of commercial operation based on the amount of energy produced by the project. Until this year, most wind projects were financed with PTCs in mind, although recently federal legislation gave wind project developers the choice between taking PTCs or some other incentive. In many cases, PTCs were sold to tax investors at a discount to provide partial financing for a project. Thus, unlike conventional projects, wind projects receive two sources of revenue: (1) payments for power produced by the project, usually from a buying utility at prices negotiated pursuant to a Power Purchase Agreement (PPA), and (2) tax benefits in the form of PTCs.

At times, particularly in spring when the weather is mild, utilities with significant wind resources on their systems may experience periods of low load when the wind is blowing, thereby creating a risk of "over generation"—meaning more power is likely to be produced than is likely to be consumed, an unstable condition. When this happens, utilities shut down thermal resources (referred to as "displacement") in order to bring generation into balance with load. Some thermal resources cannot be displaced because they are needed to provide operating reserves, to maintain reliability, to serve anticipated load, or for other reasons.

In organized wholesale power markets, generators are invited to submit DEC bids, which are bids to reduce output from particular projects. When system output must be reduced, the system operator accepts these bids in inverse order of cost so as to shut down the most expensive operating resources first. Barring an exercise of market power or some other unusual event, generators usually set their DEC bids at the marginal cost of producing power from each project. In the case of a fossil fuel plant, these DEC bids reflect the variable cost of production, mostly fuel costs.

When a positive DEC bid is accepted, project output from the chosen project is reduced, the generator pays its DEC bid amount (but saves its fuel and other variable costs), and power is supplied from the system to meet the generator's delivery obligations. Through this mechanism, the generator is made whole, load is served, and the system stays in balance by reducing project output.

Thus, in a competitive market, a power supplier will typically offer power into the market at approximately the net marginal cost of supply. These offers are usually at positive prices; occasionally, however, in the short-term there may be some rationale for negative prices. For example, a power plant might choose to bid below the short-term marginal price in order to stay in the market and avoid shut down and start up costs. In the West Texas wholesale power market (the Electricity Reliability Council of Texas or ERCOT), negative pricing was first seen in 2006, and events of negative prices increased from 2007 through 2009 both in terms of duration and magnitude. In the first half of 2008, prices were below zero nearly 20 percent of the time (2006 had less than 5% of the time). During March 2008, when negative prices were most frequent, prices were below zero about 33 percent of the time. After mostly taking the summer off, negative power prices were back to near 10 percent in October 2008.

The Northwest Power Pool (NWPP) has followed what looks like a similar pattern as 2006 ERCOT. This year NWPP experienced its first daily negative prices on Light Load Hours (LLHs) with 5% of the days in 2008 having negative LLH prices.

This year was also the first year where the Dow Jones Mid-C Daily Firm index showed negative values. From May 27 through July 6, 2008, the Off Peak index showed negative values on 18 days. The average index value for those 18 days was -$1.45/MWh with a minimum value of -$7.50/MWh and a high value of -$0.04/MWh. The 18 days of negative index values include 3 days where the non-standard Sunday Off Peak index was negative but the standard Sunday All-Day index was actually positive. If you eliminate those 3 days, the average index value for the 15 days (now covering the period May 27 through June 26, 2008) was -$0.84/MWh with a minimum value of -$1.56/MWh and a high value of -$0.04/MWh. The two days with the largest negative values happen to fall on Sundays where the standard Sunday All-Day index was positive.

When BPA needs to displace generation, it offers to supply power to project owners at very low prices reflecting their project's variable cost of generation. When BPA's offer is accepted, project output is reduced, the generator receives power from BPA at low cost, uses it to meet its load obligations, and the system stays in balance.

In the case of a wind generator receiving PTCs, receiving replacement power at low prices does not make the generator whole because if the project does not produce power, no PTCs are earned. Thus, a wind generator receiving PTCs must be paid the value of its lost PTCs and receive replacement power to be made whole if it is asked to reduce output when the wind is blowing.

Thus, a wind generator receiving a PTC would logically submit a negative DEC bid, meaning it expects to be paid an amount at least equal to the value of the PTCs to reduce output by "spilling wind." Negative bids larger than the PTCs may occur, presumably reflecting the loss of renewable energy credits needed in some states to comply with renewable portfolio standards.

Complicating the problem on the BPA system is the fact that, under the current Endangered Species Act (ESA) biological opinion (Biop), the FCRPS must provide minimum water flows in the Columbia River during certain periods of the year to assist migrating salmon. Ideally, these minimum required flows would be used to generate power to minimize spill but, coincident with these minimum flow requirements, are minimum spill requirements (either as a fixed spill volume or as a percentage of project flow) along with narrowing forebay operating ranges in several projects. These conditions severely limit the operating flexibility of the Federal System when these limitations are in effect.

Under high spring flow conditions, water flows may increase to the point where spilled water increases the risk that migrating salmon will develop the bends from nitrogen super-saturation as high flows cause water to plunge deep into water pools below federal projects, increasing pressure, and causing more nitrogen to dissolve into released water.

This risk is managed in the Biop by setting dissolved gas limits to limit the exposure of fish to high levels of dissolved gas. Dissolved gas limits are adjusted regularly by the U.S. Army Corps of Engineers based on actual river conditions. The dissolved gas limit is taken very seriously. Deviations from dissolved gas limits are not allowed under the Biop except under a power system emergency. This limits the amount of spill permitted on the system.

Nitrogen super-saturation risk can be reduced by generating power to take the momentum out of released water so as to reduce the levels of dissolved gas in released water. When dissolved gas limits are reached, the Federal system must produce power from Federal projects, instead of spilling water, to keep dissolved gas levels within Biop limits.

When the risk of excess spill rises, BPA offers replacement power at low prices to displace operation of West Coast thermal projects. When West Coast thermal generation has largely been displaced, and excess generation is anticipated, additional steps must be taken to avoid over-generation, such as paying customers to take excess generation. This risk of low load and too much energy has become more significant with the integration of more than 2,000 MW of intermittent wind projects into the FCRPS.

When over-generation occurs in the FCRPS under these conditions, one of two actions must be taken by BPA to maintain system balance. Either the output at federal projects must be reduced by spilling more water or reducing output at wind projects by curtailing wind. Spilling water raises ESA compliance issues, particularly under conditions where there is little system flexibility to accommodate additional system spill without violating the Biop or associated injunctions

This problem can be mitigated to some extent when BPA has access to relatively flat, continuously operating loads. This load profile obviously is consistent with DSI operations, which use large blocks of continuous power at all hours and on all days. Thus, once again, the nature of the power industry and the need to cope with change, in this instance technological change, suggests that the Administrator should not abandon the DSI load. The better course is to continue to use that load as a means of providing value in terms of maintaining an adequate efficient economical and reliable power system.

Historical Perspective

Historically, DSI load has provided value to BPA in connection with ensuring an adequate, efficient, economical, and reliable power supply, by providing the Administrator with flexibility to help deal with the complexities and uncertainties of marketing large quantities of Federal power. There is no compelling reason to believe that will not be the case in the future.

As noted earlier, *PNGC I* affirmed that BPA has the authority, but not the obligation, to sell power to the DSIs and clarified the proper rate directives to follow in making an initial offer. BPA believes that the proposed service plan is a proper exercise of the Administrator's discretion. The decision to serve the DSI load is consistent with the

Administrator's statutory responsibilities because DSI load will be important, as has been the case historically, in dealing with unpredictable supply and demand issues that must be reckoned with in order "to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply; . . ." 16 U.S.C. § 839(2).

The DSI load has provided enormous value to BPA in the past and, as demonstrated below, it is reasonable to believe that it will do so again. DSI loads have historically benefitted BPA by taking power in relatively flat blocks that require little or no shaping; they have taken power from BPA at light load hours, when power has historically been difficult to market; and they have provided the Administrator with additional power reserves. Therefore, in comparison to load that varies by the minute and which cannot be relied upon for reserves, DSI load service provides important benefits. Further, retaining service to DSI load has also provided BPA revenue certainty during periods when its other customers' loads were decreasing. While the aggregate DSI load has decreased substantially over the past decade due to adverse global aluminum market forces, Alcoa has shown remarkable resilience in the face of huge challenges to remain competitive. There is ample reason to believe that they will continue to do so, if provided the opportunity to predict and manage their power costs, which account for about one-third of their overall costs.

In comments filed in earlier proceedings, some preference customer groups have argued, essentially, that DSIs provided benefits to BPA in the past during times when BPA needed a "sink" for power in order to guarantee a consistent revenue stream that promoted BPA's ability to make its Treasury payments in full and on time. Now, these customers claim that BPA will never face a situation where it will need to rely on the DSIs to provide such a benefit, largely because most of BPA's firm power is locked up in twenty year contracts with the Administrator's preference customers.

This perspective ignores the central purpose of the Northwest Power Act to solve allocation problems. Prior to passage of the Act, BPA acted as the statutorily designated marketing agent for all but a small amount of electric power generated by Federal hydro-electric plants in the Pacific Northwest constructed by the United States Corps of Engineers and by the Bureau of Reclamation. *See* Federal Columbia River Transmission System Act, 16 U.S.C. § 838f.[50] BPA had no specific obligation to serve in the traditional utility sense, beyond simply marketing the Federal power available to it consistent with statute. Against the backdrop of a potential regional battle over BPA's available supply in the 1970's, Congress in 1980 passed the Northwest Power Act to address regional power needs:

[50] Congress originally authorized the BPA Administrator to market low-cost hydroelectric power generated by the Bonneville project. Bonneville Power Act, 16 U.S.C. §§ 832-832m. Subsequent marketing of power was authorized by Executive Order and by the Flood Control Act of 1944. The Transmission System Act later expanded the Administrator's marketing authority to include nearly all the electric power generated by the Federal Columbia Power River System, which consists of a series of federal dams along the Columbia River in Oregon and Washington. 16 U.S.C. § 838f.

> The basic concept of this bill is simple: It permits BPA to avoid the need for an administrative reallocation of power by giving BPA the means to reduce loads and to acquire resources so that it should be able to meet the needs of all classes of customers. . . . This is a bill to solve a power allocation problem; . . . Along with section 5, this section [7] sets forth the basic power allocation system and 'rate package' of the bill, which is common to all versions of the bill and represents a regional consensus on the division of future power supplies and power costs.

Congressman Swift remarks on S. 885, 96th Cong., 94 Stat. 2697 (1980); Cong. Rec. H9851 (daily ed. Sept. 29, 1980); *see also* Cong. Rec. S14690-91 (daily ed. Nov. 19, 1980)(remarks of Senator Jackson). To complement BPA's new service authorities, section 6(a)(2) of the Northwest Power Act obligates BPA to acquire resources on a long-term basis, in addition to making short-term purchases (up to five years), to meet its firm contract obligations under section 5. 16 U.S.C. § 839d(a)(2). The Northwest Power Act also clearly provides that the Administrator may acquire resources to replace reductions in the Federal Base System resources. 16 U.S.C. § 839a(10). All that is to say, if BPA doesn't have enough power to meet load, it has the authority to, and must, acquire the power. Clearly, preference customers err when they argue that BPA should only serve the DSIs if it needs a sink for its existing power.

The preference customers' perspective is apparently based on the view that things will always be as they are now when, in fact, the Pacific Northwest has been, since passage of the Northwest Power Act, essentially subject to repeated dramatic and unanticipated change. On this level, no one knows with certainty what loads and resources might look like in the years ahead. For this reason, BPA has recognized that it "must position itself to be successful in the short-term and the long-term, so it must think in terms of short-term and long-term consequences." 1996 Wholesale Power Rates Final Record of Decision at 81. Moreover, the Administrator must always be mindful that "section 7(a) of the Northwest Power Act requires BPA to recover its costs 'under all economic conditions'." *Id.* at 169.

In meeting these objectives, DSI load has always been part of the mix and, until recently, the general assumption seemed to be that at various times, the DSI load was "at risk" and worth preserving, even if that took extraordinary measures. As noted in the 1996 ROD: "In 1986, DSI loads and revenues were at risk because of low aluminum prices. Today they are at risk because of competition." *Id.* at 169 Thus, efforts in the 80's to provide a variable rate based on the market price of aluminum enabled the DSIs to operate in both good market conditions and bad. This benefitted BPA financially, to be sure, because BPA would have otherwise been forced to unload DSI power into an underdeveloped market which would have assured receiving less revenue than BPA would receive from DSI revenues under the IP rate.

Preservation of the DSI load in the 1980's, however, provided a perhaps even greater benefit in the 1990's, when BPA was facing the problem of its cost-based rates being above prevailing market prices. The market for power was routinely offering prices that were competitive with BPA's PF preference rate, and some of BPA's preference customers threatened to find whatever means they could to get out of their existing BPA power sales contracts. As a consequence, facing a rapidly changing and increasingly competitive market for wholesale electric power, Congress in 1995 enacted P. L. 104-46, addressing Bonneville's power marketing authority. Energy and Water Development Appropriations Act of 1996, Pub. L. No. 104-46. The legislation modified regional preference to allow BPA to effectively market surplus Federal power abandoned by regional customers. See, Excess Federal Power provisions, 16 U.S.C. 832m(b). Without the legislation, provisions of BPA's authorizing legislation severely limited BPA's marketing flexibility with respect to such power, putting the agency at a competitive disadvantage and restricting the potential revenues from sales of such power. Sales or exchanges of surplus power which is surplus for reasons other than the reasons set out in the new legislation continued to be subject to existing marketing restrictions.

BPA's preference customers sought to reduce the amount of Federal power under BPA's then long-term power, 20-year power sales contracts. "[P]rojections of public utility purchases from BPA have been reduced to account for utilities that are seeking actively other suppliers. Supplemental Loads and Resources Study, WP-96-E-BPA-57, at 13; Supplemental Loads and Resources Study Documentation, Vol. 1, WP-96-E-BPA-57A, at 229. Without the certainty of the expected revenues from sales to DSIs, BPA's financial health would have further deteriorated. Some preference customers asserted that the situation was even more dire than BPA supposed and some of these same customers had already mounted legal challenges to obtain greater access to the competitive market:

> Customers represented by the Western Public Agencies Group (WPAG) argue that BPA has misjudged its position in the wholesale market, and has grossly underestimated the desire of its preference customers to diversify their power supply. Beck, et al., WP-96-E-WA-13, at 6, 10-11. They note that, at the time their testimony was submitted in November 1995, preference customers had made submissions to BPA pursuant to their power sales contracts to reduce their load on BPA by over 780 aMW, and that they expected to see this number increase. Id. Since that time, some of these customers have sued BPA in an attempt to access alternative power suppliers.

1996 Wholesale Power rates Final record of Decision at 18.

Thus, the Administrator was facing the loss of both public load and DSI load. The preference customer side of the problem was dealt with by a combination of contract amendments that were offered in order to obtain load commitments from some preference customers so that others, who were more adamant regarding access to the market, could be provided with the ability to diversify their load.

Preserving the DSI load was equally problematic. The loss of DSI load was a virtual certainty because, in a competitive market, the nature of the DSI loads made them particularly susceptible to competitive encroachment. As noted in the 1996 ROD:

> The DSIs can demand better prices from BPA's competitors because they offer valuable loads: they have high load factors and their loads are fairly constant throughout the day and over the course of the year. Thus, their loads are cheaper to serve than loads that vary more, and they are the objects of more intense competition than BPA's other loads. Moorman, Evans, E-BPA-65, at 5.

Part of BPA's strategy to resolve the loss of DSI load was a successful effort to retain as much of the DSI load as possible in spite of the fact that BPA's cost-based rates were higher than rates for power that could be purchased on the open market. Retention of this load supported BPA's ability to meet its financial obligations in full and on time, including its Treasury repayment obligation. As BPA observed at the time:

> As in 1986, so today BPA must be concerned with its resource planning, financial strength, and rate stability. As in 1986, so today BPA faces the prospect of power surplus and unrecovered fixed costs if it loses substantial load. That the DSIs may be unwilling, rather than unable, to pay higher rates is immaterial; if they purchase power elsewhere because BPA's rate is above the market, the consequences the Variable Industrial Rate ROD was intended to forestall will come to pass. Like BPA, BPA's customers operate in a competitive market, and must set rates competitively to retain load. The industrial customers of BPA's public body and cooperative customers are pressuring their utilities to set competitive rates or to provide them with direct access to the market so they can reduce their power costs. Hill, et al., WP-96-E-BPA-51, at 4.

Faced with the sudden changes in the market and the resulting high likelihood that the DSIs would exercise their contractual right to remove their load from BPA on nine months notice, BPA acted to protect its overall revenues and ability to recover its costs by negotiating block sale contracts, committing the DSIs to place a substantial amount of load on BPA for five years. *See* Administrator's Record of Decision, 1996 Power and Transmission Rate Proposal, § 2.2 at 18; see also, id. § 8.

Due to the many unanticipated changes that the electricity market has seen over the last two decades, BPA believes it would be short-sighted and unwise to conclude that retention of DSI load could never provide significant value to BPA in the future in much the same way as it has in the past. As the above illustrates, notwithstanding WPAG's comment on the new long-term power sales contracts between BPA and its preference customers, service to diversified customer loads, i.e., public body, cooperative, federal agency, direct service industries, and investor-owned utilities, provides a flexible and sound business approach to meet the uncertainties of the future. Given the current economic crisis and market conditions, it is certainly within the realm of possibility that BPA could find itself in a position similar to the 1990s, where BPA's cost based rates exceed prices available on the market. Recently, market prices have declined significantly while BPA has just proposed a rate increase. In fact, daily prices in the applicable markets have at times been significantly lower than some of BPA's cost-based rates. No one knows what the end result of these volatile market forces will be if the economy continues to decline, nor does anyone know with certainty what conditions in the power market will be like when the economy begins to improve.

Even at this time, the gap between market prices and BPA rates has narrowed considerably primarily due to depressed prices for natural gas. Natural gas is a primary driver of prices in the west coast markets because the marginal cost resource for the region is the combined cycle combustion turbine, which operates on natural gas. To the extent that fuel costs, in the form of natural gas, are depressed, that means that operators of combined cycle combustion turbines can offer lower prices in the market, which creates competition and drives market prices down. A recent Wall Street Journal article stated:

> Natural-gas futures fell to a fresh seven-year low as a glut of the fuel and tepid demand outweighed diminishing concerns about storms in the Atlantic. Natural gas for September delivery on the New York Mercantile Exchange fell 6.7 cents, or 2.1%, to settle at $3.096 a million British thermal units. That represents the lowest settlement since Aug. 14, 2002, and marks the ninth consecutive trading day of declines in gas futures.

"Natural Gas Falls to Seven Year Low", *Wall Street Journal*, August 19, 2009. The same article noted that natural gas supplies are expected to be less subject to unanticipated price spikes caused during hurricane season in the Gulf of Mexico area. The continued declines, even in the midst of hurricane season, underscore how booming onshore domestic gas production has led to an overabundance of the fuel, resulting in a market that relies less on Gulf output. In recent years, when the Gulf represented a fifth of the U.S. gas production and markets were strained, any threat of storms could send prices soaring. But gas output from the Gulf now accounts for about 11% of domestic supply as producers have increasingly moved on shore to tap gas-rich formations known as shales, putting less supply in the path of storms and boosting overall output from these new fields. Id. These types of developments in the energy industry are simply a fact of life and, because they cannot always be anticipated, planning for the future cannot be done on the basis of a rose-colored haze that simply presumes the status quo will be maintained, even over a relatively short time horizon.

Some preference customers have suggested that BPA need not worry about the future now because BPA's preference customers have executed long term contracts that contain take-or-pay obligations that protect BPA's revenues. That fact does provide potential mitigation of some of the issues faced by BPA in the 1990s. However, a significant portion of BPA contracts or load following contracts respond to overall economic conditions. In addition, BPA's surplus energy above critical water that is primarily being relied upon to serve Alcoa's load is not sold through take or pay contracts, is priced at market, and the revenue is subject to overall economic conditions.

In spite of the existence of these contracts, there is no guarantee that, overall, demand could not become depressed in the future and power supplies plentiful. Planning for the future must recognize that market prices are subject to supply/demand market fundamentals that are cyclical in nature but are also subject to volatility caused by unanticipated events and changes. Poor economic conditions, for example, can cause a decrease in business activity that can lead, in turn, to relocation of business enterprises and consequent population drift, all of which can result in localized suppression of demand for power and, assuming normal supply parameters, lower market prices for power. Current economic conditions are, in fact, having some effect with respect to suppressing demand for power. Similarly, in a market situation where BPA's rates were higher than market prices, having the DSI load available could well help the Administrator in retaining sufficient load to assure Treasury repayment as he weighs the cost and benefits of allowing customers to diversify their supply portfolios, as was done in the mid-90s, in the interest of achieving the lowest rates possible for consumers and diversifying the region's power sources in the interest of maintaining an adequate, efficient, economical and reliable power supply.

Thus, the issue raised by the preference customers (i.e., that the take-or-pay requirement in the long term Regional Dialogue contracts obviates any business need to continue service to DSI load) is overly simplistic and based on a static view of the future that, if history is any guide, is not supportable. Resolution of the complex issues that can arise in the management of the Federal FCRPS, planning for the future integrity of regional power supply, and mitigating the risk created by potential events that are unpredictable cannot reasonably be accomplished by taking the view that take-or-pay protection in requirements contracts will be all that is necessary to plan for the future. Instead, market fundamentals suggest that it is a reasonable business proposition for BPA to increase the certainty of its revenues through serving this load.

It is not as though BPA would, at a later time, have the ability bring that load back on line. The DSIs customers currently have no viable long-term alternative for their power needs and a decision not to sell power to DSIs would almost surely have the immediate consequence of the plants shutting down with a very high likelihood that they may never resume production.

Conclusion of Intangible Benefits

While adjustments for these intangible benefits to BPA are not included or relied upon here because they are more qualitative than quantitative at this time and therefore do not presently affect BPA's decision to offer the Block Contract, BPA believes it is important to acknowledge these prospective benefits. BPA continues to believe its forecast of positive net revenues is probably conservative, inasmuch as the sale to Alcoa encompasses certain additional intangible and qualitative benefits to BPA's operations.[51]

[51] Finally, it is worth noting that BPA and Alcoa included a provision in the Block Contract with respect to the possibility that Alcoa may provide to BPA certain additional reserve products or restriction rights that may only be supplied by the large, flat, but potentially flexible load at an aluminum smelter.
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VI. PNGC II

The following analysis largely restates BPA's analysis of *PNGC II*, as set forth in the record of decision dated November 13, 2009, for the 14-month sale by BPA to Port Townsend Paper Company of 20.5 aMW.

On August 28, 2009, the Ninth Circuit issued its opinion in *Pacific Northwest Generating Cooperative v. BPA*, 580 F.3d 828 (9^{th} Cir. 2009) ("*PNGC II*"). BPA reads *PNGC II* as requiring that if the Administrator exercises his discretion to serve a DSI customer, the decision to serve must be consistent with "sound business principles," meaning in this context that the benefits to BPA of serving the DSI load must equal or exceed BPA's cost of serving the load during the period of service or, if they do not, there must be a demonstrated and realistic prospect that the short-term net cost of providing DSI service will be offset by positive net benefits of future DSI service. BPA refers to the *PNGC II* requirement herein as the "Equivalent Benefits Test".

As noted, the DSIs disagree with BPA's reading of *PNGC II*. Indeed, the DSIs' position comports with BPA's view of its statutory mandate to assure the Pacific Northwest, including the DSIs, an adequate, efficient, economical and reliable power supply. However, inasmuch as BPA believes the most sustainable reading of *PNGC II* is that service to the DSIs must be conservatively measured against an equivalent benefits test, BPA has constrained its consideration of Alcoa service options to those that will satisfy that test. Absent the equivalent benefits test, BPA would have considered other, longer-term service options. The Transition Period and Second Period only come into play if the Court determines that the equivalent benefits test should not apply.

Taking the opposite position, the PPC/ICNU comments state that BPA's approach "appears to recognize that the Ninth Circuit's recent decisions have established that BPA is authorized to serve the DSIs only if the agency demonstrates that doing so is calculated to financially benefit the agency." PPC at 1. PNGC agrees with and adopts the PPC comments.

Before addressing the more fundamental issue of the meaning of *PNGC II*, and whether the Equivalent Benefit Test is correct, we will address the subsidiary comments raised. Alcoa offered several points it believed BPA needed to consider in making its decision regarding the Block Contract, including the fact "BPA will deliver the same amount of power to Alcoa in every month rather than 'shaping' its power resources to meet varying electric loads as it does for most of its other customers." Alcoa at 6. Alcoa also points to other benefits that it believes provide value to BPA under the contract, including the waiver of any right to request surplus power (4), provision of reserves (6), and preservation of potential future benefits (7). Moreover, Alcoa states they "would prefer a longer-term contract because it could justify long-term capital expenditures at the Intalco plant and provide economic stability to the many people who depend on the plant's operation for their economic well being.

With regard to the concerns expressed by Alcoa, BPA understands, and is sympathetic with, the fact that long-term planning by Alcoa is impaired by the short-term nature of the proposed contract. If Alcoa is going to make capital investments, it needs reasonable certainty as to their future recovery. BPA's proposal does not allow that reasonable certainty, unless Alcoa can recapture its investments in the short period of the contract, and BPA has no basis to deny Alcoa's assertion that the time period of the contract is too short in that regard. However, BPA's analysis, as discussed in this ROD, looks into the future to see where the breakpoint is for purposes of satisfying the equivalent benefits test, which BPA forecasts is a 17-month contract.

With regard to the test itself, BPA did not mean to state or imply that benefits must exceed costs. Rather, as BPA reads *PNGC II*, it is sufficient if benefits equal or exceed costs. As to the demonstration of benefits, BPA agrees with Alcoa and does not believe that an "accounting analysis" is necessary to quantify the costs and benefits. However, certain costs and certain benefits can be reasonably quantified, and in that case it is reasonable to do so. BPA has presented that quantification in this record of decision. In the case of certain other benefits whose values are a matter of judgment, such as for example a litigation waiver or a waiver of a right to argue certain positions, we are not foreclosing such valuations, and did not foreclose them.

a. BPA's Interpretation of *PNGC II*

PNGC II unequivocally requires that a decision to serve a DSI customer be consistent with sound business principles: "Given that BPA is not obligated to sell to the DSIs and that its actions are generally reviewable under the 'sound business principles' standard, it follows that a decision by BPA to enter into a contract with a DSI, like other nonobligatory contractual decisions made by the agency, *see APAC*, 126 F.3d at 1171, must also conform to the 'sound business principles' standard." *PNGC II*, 530 F.3d at 835. In terms of what is demanded by that standard, the following and other statements in the Court's decision leave an overall and lasting impression that benefits must approximate or exceed costs:

> In short, neither the record in this case nor the record in PNGC contains any financial or other business analysis or evidence to support the agency's assertion that future benefits to the agency are (a) likely or (b) sufficiently large to make the decision to give $32 million away a sound business decision.

Id. at 844. While that passage uses the word "or" between (a) and (b), we do not believe the Court would divorce the two. In other words, if the benefits were likely but not equal to the costs, or huge but unlikely, the tenor of the Court's decision causes BPA to believe such benefits would be insufficient to satisfy a "sound business decision" test.

The Court elsewhere analogizes DSI sales to the incurrence by a utility of a non-necessary expense. *Id*. at 839, citing *McCarthy v. Middle Tenn. Elec. Membership Corp.*, 466 F.3d 399 (6th Cir. 2006). In the context of providing power at the lowest cost consistent with sound business principles, if the DSI sale comes at a net cost, with the consequence that other customers' rates are increased, *PNGC II* appears to indicate that sound business principles would be violated. *Id*.

That conclusion is bolstered by the Court's discussion of parties' arguments that under the sound business principles, it would never make sense to sell power at the IP rate when market rates exceed that rate. The Court disagreed, but did so in a fashion that indirectly reinforced the Equivalent Benefits Test, as BPA has described it above (benefits to BPA of serving the load must equal or exceed BPA's costs of serving the load during the period of service or, if they do not, there must be a demonstrated and realistic prospect that the short-term net cost of providing DSI service will be offset by positive net benefits of future DSI service). The Court stated:

> We can envision several situations in which BPA might reasonably conclude that a below-market rate sale to the DSIs is a sound business decision. First, as the court alluded to in *PNGC*, BPA's governing statutes likely require it to offer power within the Pacific Northwest at established rates before the agency may sell power outside the region. If so, BPA might reasonably enter into a contract with the DSIs at the IP rate so as to "free up power to sell outside the Pacific Northwest."
>
> Second, BPA has asserted that the physical sale of power to the DSIs has indirect benefits that might offset a below market rate sale. For example, BPA noted in its letter explaining its justifications for the amended contract with CFAC that "DSI loads have historically benefitted BPA by taking power in relatively flat blocks that require little or no shaping; they have taken power from BPA at light load hours, when power has historically been difficult to market; and they have provided the Administrator with additional power reserves." These and other non-financial benefits to BPA could very well justify a less-than-market rate sale, but they have no direct application when, as here, BPA is not in fact physically selling power to the DSIs.
>
> Third, a soundly run business might reasonably offer a large customer a short-term discount with the expectation that the customer's future business at higher prices will more than make up for the short-term loss of revenue. Similarly, a reasonable business might offer a short-term discount to a customer in order to diversify its customer base or to offload unused capacity.

PNGC II, 530 F.3d at 835-836 (footnotes and citations omitted).

With regard to the first scenario, freeing up power to be sold outside the Northwest, two observations are in order. First, *Kaiser Aluminum & Chemical Corp. v. BPA,* 261 F.3d 843 (9th Cir. 2001), establishes that where BPA has a rate for surplus power sales that provides for the sales at a market rate, regional preference is satisfied if the power is made available first in the region at the same rate it could be sold for out of region. That means that if a DSI is willing to pay the higher rate, it would be entitled to the power. However, in that case, there would be equivalent benefits because DSI revenues and lost opportunity cost would be equal. Second, when the Court speaks of "reasonably" entering a DSI contract to free up power for sale outside the region, there is no indication that the Court would find the contract reasonable if the DSI contract resulted in a lost opportunity cost to BPA relative to out-of-region sales revenues.

In the second scenario, where the Court speaks of certain benefits such as sales in flat blocks possibly justifying a less-than-market rate sale, BPA reads the Court's opinion as indicating that the DSI revenues plus the other benefits must equal or exceed the lost opportunity costs of a less-than-market rate sale. In other words, the Court, while not requiring an accounting analysis, would at least require the Administrator to opine that the DSI revenues and listed benefits equal or exceed the costs, and to state why.

Finally, in the third scenario, the Court is explicit that a short-term discount could be justified if "higher prices will more than make up for the short-term loss of revenue." That all but says benefits must match costs so that there is no net cost over time. As to diversifying BPA's customer base, the Court rejected BPA's widespread use arguments in *PNGC I* so it is difficult to envision the Court allowing BPA to ascribe any real value to this. And, certainly, implicit in the Court's reference of a sale to "offload unused capacity" is the sense that the sale is the best, if not the only, economic use of the otherwise unused capacity. However, BPA is not in that situation.

b. Imposition of an Equivalent Benefits Standard Is Inconsistent With BPA's Enabling Statutes

As indicated, BPA has structured the Block Contract to comport with its reading of what the Court has required in *PNGC II*, a reading that Alcoa argues is wrong or overly conservative. BPA is not persuaded that the opinion can reasonably be interpreted in the fashion advanced by Alcoa. However, BPA does believe *PNGC II* errs by constraining the Administrator's discretion to serve DSI customers to a degree that is not in concert with BPA's enabling legislation. The Northwest Power Act expressly provides that one of BPA's key missions is "to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply, . . ." 16 U.S.C. § 839(2). This purpose encompasses all BPA customers, including direct service industry customers, investor owned utilities, federal agency, and public body and cooperative customers (preference customers). It is true that Section 5(d)(1)(B) of the Northwest Power Act authorizes, but does not require, the Administrator of BPA to sell power to DSI customers once their "initial" contracts under the Act terminate. 16 U.S.C. § 839c(d)(1)(B); *PNGC I*, 550 F.3d at 866. It is equally clear that by referring to an "initial" contract Congress envisioned the potential for continuing DSI sales beyond expiration that contract. Section 5(d)(1)(B) requires only that "[s]uch sales shall provide a portion of the Administrator's reserves for firm power loads in the region." 16 U.S.C. § 839c(d)(1)(B). Section 5(d) does not otherwise mention, let alone require, that such sales shall provide other benefits to BPA or the region or be subject to a strict cost-benefits analysis that would seemingly preclude service in all but a few narrow sets of circumstances.

The rate charged to DSI customers further indicates that Congress intended that sales to DSI customers beyond the "initial" NPA contract would be the rule, rather than the exception. When the Administrator exercises his discretion to sell power to DSIs under section 5(d)(1)(B), the rate for such sales must be established pursuant to section 7 of the Act. 16 U.S.C. § 839c(a)("All power sales under this Act . . . shall be at rates established pursuant to section 7."); *see also PNGC I*, 550 F.3d at 869. For the period prior to July 1, 1985, but only for that period, section 7(c) of the Act required the IP rate to recover the cost of resources the Administrator determined were required to serve the DSI load. 16 U.S.C. § 839e(c)(1)(A); *see also* H.R. Rep. No. 96-976, 96th Cong., 2nd Sess., pt. 2, at 36 (1980). In other words, prior to July 1, 1985, the rate was based on cost of service. After July 1, 1985, however, section 7(c) requires that the IP rate shall be based upon the Administrator's rates to his public body and cooperative customers (preference customers) and the typical margins they include in their rates to their retail industrial customers, adjusted for certain specified factors, including the value of the reserves the sales provide the Administrator. 16 U.S.C. §§ 839e(c)(2), 839e(c)(3); *see also* H.R. Rep. No. 96-976, at 36. Consequently, when the Administrator now exercises his discretion to sell power to DSIs under section 5(d)(1)(B), the sale must be at the section 7(c) IP rate that is linked to BPA's cost of serving preference customers, not a rate tied to market, specific resource purchases, DSI cost of service, or benefits other than reserves. In other words, for sales beyond 1985, Congress specified that DSIs be served at a rate that is roughly in parity with rates paid by industrial load served by preference customers. It is not clear why the Court appears to believe that Congress would design a rate to achieve such parity and also intend that it be used only in limited and narrow circumstances, as required by *PNGC II*.

Notwithstanding the Administrator's authorization to serve and this clear statutory expression that the rate for DSI service is linked to the rate for service to BPA's preference customers, the *PNGC II* opinion effectively mandates that the Administrator can only serve the DSIs if he can do so at no net costs, *i.e.*, in a way that results in no differential between the cost of serving the DSIs and the revenues resulting from service at the statutory section 7(c) IP rate. *PNGC II*, 580 F.3d at 835. In other words, if serving the DSIs and application of the statutory IP rate means that some costs of serving the DSIs would not be recovered through the section 7(c) IP rate, *PNGC II* forbids the Administrator from serving the DSIs unless he can show that those costs of service are offset by equal or greater benefits resulting from the service. In so doing, BPA is concerned that *PNGC II* trumps the statutory rate directive in a manner that, for the reasons next explained, has no basis in law, and improperly undermines the Administrator's authority under the Northwest Power Act "to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply, . . ." 16 U.S.C. § 839(2).

PNGC II relies upon a misreading and misapplication of "sound business principles" to arrive at its conclusion. The Court posits that (a) BPA's discretionary actions "are generally reviewable under the 'sound business principles' standard," *PNGC II* 580 F.3d at 834; (b) sound business principles means DSI service should come at no net cost to

BPA: and (c) the Administrator cannot serve the DSIs if benefits do not equal or exceed net costs of service. *Id*.

However, in developing this logic, the Court appears to confuse statutory rate setting directives, which reference "sound business principles" with BPA's decisions regarding service to DSI customers, which are not circumscribed by such references. The Court states:

> In sum, we hold that BPA's voluntary decision to contract with the DSIs, like its other non-obligatory contractual choices, must conform to the congressionally imposed requirement that the agency act in a manner "consistent with sound business principles." *See* 16 U.S.C. §§ 838g; 839e(a)(1); 825s. The mere fact that BPA has chosen to contract with a DSI at the statutorily authorized IP rate does not insulate the decision to contract from review under the "sound business principles" standard. (Footnote Omitted.)

PNGC II, 580 f.3d at 835. The first two references are to ratesetting, not a decision to serve or the incurrence of costs. Rate decisions and power service decisions are entirely separate in the Act, *compare* 16 U.S.C. § 839c (sale of power) *with* 16 U.S.C. § 839e (rates), and for purposes of what final actions are subject to judicial review, *compare* 16 U.S.C. § 839f(e)(1)(B)("sales, exchanges, and purchases of electric power under section 5") *with* 16 U.S.C. § 839f(e)(1)(G)("final rate determinations under section 7"). Section 7(a)(1) of the Northwest Power Act provides that when the Administrator sets rates for power and transmission "[s]uch rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, . . ." 16 U.S.C. § 839e(a)(1). This directive applies to all BPA rates, not just rates for DSI service.

Moreover, this statutory provision is not, as *PNGC II* determined, a directive that should be transported from the rate directive setting of the Act to which it explicitly applies and then applied to require that decisions *to sell* power be subject to identical standards. Ratemaking and power sales are two distinct activities, each of which has its own distinct requirements. The directive is limited to the establishment of rates to recover costs, *costs which have already been and will be incurred*, and to recover them consistent with sound business principles. Thus, the directive is explicit and limited, requiring that rates be set in a manner that underscores the importance of BPA recovering its cost in a manner consistent with assuring that BPA's treasury repayment obligations in full and on time. This reading is borne out by subsequent language in the same sentence of section 7(a) that refers to rates recovering "the other costs and expenses incurred by the Administrator pursuant to this Act and other provisions of law." 16 U.S.C. § 839e(a). As the Court observed in *Golden Northwest Aluminum, Inc. v. BPA*, 501 F.3d 1037, 1052-53 (9th Cir. 2007), this ratesetting requirement "presupposes that BPA knows its costs or, at the very least, that it estimates them 'in accordance with sound business principles.'" Section 7(a) takes recovery of costs, regardless of how or when they were incurred, as a fundamental precept of rate making. The provision has absolutely nothing to do with, and is inapplicable to, decisions regarding sales to statutorily identified customer classes, or for that matter, sales of surplus power.

Even if section 7(a) could somehow be seen as applying to a decision to serve, the more specific language of section 7(c) would govern. Congress addressed section 7(a) in the context of the more specific rate directives, including section 7(c), as follows:

> Section 7 of the legislation sets out the requirements BPA must follow when fixing rates for the power sold its customers under this legislation. *Subject to the general requirements (contained in section 7(a)) that BPA must continue to set its rates so that its total revenues continue to recover its total costs, BPA is required by the legislation to establish the following rates . . . [preference customer, exchange, DSI, other rates listed]*

H.R. Rep. No. 96-976, 96th Cong., 2nd Sess., pt. 2, at 36 (1980)(emphasis added). The import of this is that specific rate directives, including section 7(c), are not overridden by section 7(a) unless and, then, only to the extent necessary to assure total cost recovery. No question existed in *PNGC II* that DSI service would somehow jeopardize total cost recovery by BPA. Indeed, BPA's cash reserves dwarfed the cost incurred by BPA to provide DSI service. As to the rates themselves, BPA established the rates to recover the costs of the monetary benefits to the DSIs.

So, too, section 9 of the Transmission System Act of 1974, 16 U.S.C. § 838g, also cited by the Court, deals with ratesetting, but only ratesetting. It includes language that BPA's charges for the sale of power and transmission shall be established based on a number of factors, including "with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles." *Id*. Here, again, this is a directive dealing with the setting of charges, not with decisions by the Administrator whether to sell power. In any case, even if this language has any application to DSI ratesetting, it must be reconciled and harmonized with the very specific language of section 7(c) concerning what costs the DSI rate is to recover, not used as a basis to override it. As indicated, BPA is very concerned that *PNGC II* effectively trumps the section 7(c) directive by applying these general "sound business principles" ratesetting references to the Administrator's service decisions.

In *Cal. Energy Comm'n v. BPA*, 909 F.2d 1298, 1307-08 (9th Cir. 1990), the Court rejected claims that a BPA intertie access policy must be rejected because it failed to maximize BPA returns. Reviewing the language in 16 U.S.C. § 838g that rates be set "with a view to encouraging ... the lowest possible rates to consumers . . ." the Court observed with some prescience:

> nearly every action by BPA has some arguable impact on future rates. If the strict interpretation of the "lowest possible rates" standard advanced by DSI[] were accepted, the discretion that Congress vested in the Administrator would be eliminated.

Id. The Court in *Cal. Energy Comm'n,* clearly recognized in the preceding passage that a revenue maximization test would inappropriately rob the Administrator of the discretion afforded him by Congress. *PNGC II* appears to swing full tilt in the other direction, inconsistently imposing a rigid cost/benefit test that all but eliminates the Administrator's discretion.

In sum, the statutory requirements that BPA "establish" or "periodically review and revise" or "fix and establish" its rates "at the lowest possible rates to consumers consistent with sound business principles" cannot be read as concerning anything more than just that, the establishment of rates and the recovery of costs that have been and will be incurred. 16 U.S.C. § 838g; 16 U.S.C. § 839e(a)(1). The rates can be no lower in total than would be consistent with sound business principles so as to assure total cost recovery. In addition, rates are to be established to "recover, in accordance with sound business principles, the costs" borne by BPA. 16 U.S.C. § 839e(a)(1). Recovering the costs is, however, a matter separate from the incurrence of the costs, including through decisions to serve.

PNGC II also relies in passing on language of section 5 of the Flood Control Act of 1944, 16 U.S.C. § 825s, which provides that in marketing the output of Corp of Engineers' reservoir projects, the Secretary shall "transmit and dispose of such power and energy in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles . . ." Here, again, this reference to lowest possible rates to consumers consistent with sound business principles cannot serve to override the specific directive of Northwest Power Act section 7(c) or the authorization to serve in section 5(d).[52] Even as a marketing matter, this language supports service to the DSIs rather than negates it. If *PNGC II* is to be read as saying that there can be no DSI service if it comes at a net cost, then the Flood Control Act language should apply in equal fashion to all service decisions since the consumers referred to in section 5 of the Flood Control Act of 1944 encompass preference customers, federal agencies, and aluminum companies. That would mean that if the power could be sold at market, such that one set of consumers' rates could receive a greater revenue credit and so have lower rates, that is what BPA should do. But that makes absolutely no sense since there is no basis in the language to elevate one class of regional customers over

[52]Giving effect to the whole of section 5 the term "consumers" means the entities to which BPA markets Federal power. Those "consumers" or entities are identified within the language of the section itself. In pertinent part, section 5 provides, "in order to make the power and energy generated at said projects available in wholesale quantities for sale on fair and reasonable terms and conditions to facilities owned by the Federal Government, public bodies, cooperatives, and privately owned companies." The last of these consumers, "privately owned companies" is a reference to privately owned aluminum plants In testimony before the subcommittee of the Senate Committee on Commerce drafting Section 5 language, Arthur Goldschmidt, Director of the Division of Power, Department of Interior, testified that: "At Bonneville . . . we seek that kind of a customer, such as aluminum or magnesium, or carbide, where they take juice in huge quantities and take it around the clock. . . . That base-load operation is the kind of operation that we prefer to have, and the private company operating that type of operation prefers to be upon our power line because it wants to have a direct service with the actual generation of the power. . . . For that reason all of the aluminum in the Northwest is directly on our lines, both the Government-owned aluminum and the privately owned aluminum plants, . . ." Bonneville Power Administration, legislative History of Section 5 Flood Control Act of 1944.

another in terms of lowest possible rates. Also, the *Cal. Energy Comm'n* case rejected that very approach. The power marketing administrations do not operate on a profit-making basis, but must balance a number of considerations.[53]

Finally, *PNGC II* references in passing section 9(b) of the Northwest Power Act. That section requires that the "Secretary of Energy, the Council, and the Administrator shall take such steps as are necessary to assure the timely implementation of this Act in a sound and business-like manner." 16 U.S.C. § 839f(b). As the legislative history makes clear, the purpose of this provision was to recognize the respective responsibilities of the Department and the Administrator, so that "Bonneville cannot be delayed in its activities while these [DOE] officials review contracts, budgets, labor agreements, and other matters" and the legislation be "carried out effectively and in a timely manner." Cong. Rec. H 10685 (November 17, 1980)(Remarks of Rep. Dingell). A requirement to take such steps as are necessary to assure the timely implementation of the Act in a sound and business-like manner goes to, as it says, timely implementation, and cannot be read to say that every decision, discretionary or otherwise, of the Administrator must be consistent with "sound business principles," as that term has been defined by the *PNGC II* court. Yet, that is precisely what *PNGC II* appears to require by setting sound business principles up as the yardstick by which to test the Administrator's decision to serve the DSIs. If section 9(b) did have the broad application evidenced by *PNGC II*, Congress need not have referenced sound business principles, as it did, in connection with the establishment of rates.

BPA has broad authority to act in a businesslike manner, but that authority rests on the Administrator's expansive contracting authority under section 2(f) of the Bonneville Project Act, 16 U.S.C. § 832a(f). That section provides:

> Subject only to the provisions of this Act, the Administrator is authorized to enter into such contracts, agreements, and arrangements, including the amendment, modification, adjustment, or cancellation thereof and the compromise or final settlement of any claim arising thereunder, and to make such expenditures, upon such terms and conditions and in such manner as he may deem necessary.

The Congressional intent behind this language was "to enable the Administrator to employ business principles and methods in the operation of a business enterprise . . ."

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[53] Five circuits have considered whether the widespread use clause of section 5 of the Flood Control Act provides law to apply to an administrator's decisions in power marketing. Each has concluded that it does not. *See Salt Lake City v. Western Area Power Administration,* 926 F.2d 974, 979 (10th Cir. 1991); *City of Santa Clara v. Andrus,* 572 F.2d 660, 668 (9th Cir. 1978), *cert. denied,* 439 U.S. 859 (1978); *Brazos Elec. Power Coop. v. Southwestern Power Admin.,* 819 F.2d 537, 543-44 (5th Cir. 1987); *Electricities of North Carolina v. Southeastern Power Admin.,* 774 F.2d 1262, 1266 (4th Cir.1985); *Greenwood Util. Comm'n v. Hodel,* 764 F.2d 1459, 1464-65 (11th Cir.1985).

H.R. Rep. No. 777, 79th Cong., 1st Sess., 3 (June 21, 1945). The Northwest Power Act extended section 2(f)'s expansive authority to enter into contracts under that Act.[54]

With the passage of the Northwest Power Act, the Administrator's responsibilities were significantly expanded. The broad grant of contracting authority to enable the Administrator to employ business principles and methods was incorporated into BPA's statutes as a means to enhance BPA's ability to implement its statutory authorities, not to restrain them.

Earlier cases illustrate the important distinction of bringing sound business principles into play when Congress has not clearly addressed a matter and it is necessary to fill the gaps, versus the situation where Congress has specifically authorized the Administrator to take an action, such as serve DSI customers. In cases such as *Bell v. BPA*, 340 F.3d 945 (9th Cir. 2003) (buying out contractual obligations), *Aluminum Co. of America v. BPA*, 903 F.2d 585 (9th Cir. 1989) (wheeling non-Federal Power), and *Dep't of Water & Power of the City of Los Angeles v. BPA*, 759 F.2d 684, 693 (9th Cir.1985) (intertie access), the statute did not address the matter at hand and there was, in the words of *Association of Public Agency Customers v. BPA*, 126 F.3d 1158, 1170 (9th Cir. 1997) (sale of transmission to DSIs), a gap to fill with "how best to further BPA's business interests consistent with its public mission." Indeed, the Northwest Power Act does not address the monetization of contracts, so there again, as in *PNGC I*, it is appropriate to determine what is prudent and businesslike. In other cases, the issues dealt with rates, and a legitimate question arose as to compliance with the sound business principle rate language. *See, e.g., Public Power Council, Inc. v. BPA*, 442 F.3d 1204, 1206 (9th Cir. 2006)(rate adjustment). Here, however, where the question in the first instance is whether the Administrator may choose to serve the DSIs—a contractual decision that then leads to the separate question of monetization at issue in *PNGC II*—Congress authorized but did not require the Administrator to provide service to DSI customers. 16 U.S.C. § 839c(d)(1)(B). There is simply no reason to look to section 2(f) or 9(a) when reviewing the Administrator's decision to serve DSIs, for the simple reason that DSI sales are authorized and offered under section 5(d)(1)(A), not section 2(f), 9(a) or any other provision of BPA's enabling legislation.

BPA's concern that the *PNGC* panel fundamentally misreads the statutory references to "sound business principles" as having expansive sweep is confirmed by the following passage:

> Even more relevantly, the Sixth Circuit, in interpreting *a statutory directive very similar to the statutory requirements at issue here*, concluded that there was sufficient law to apply. *See* McCarthy v. Middle Tenn. Elec. Membership Corp., 466 F.3d 399 (6th Cir. 2006). In *McCarthy*, the Sixth Circuit held that an electric cooperative's decision to incur "non-necessary expenses," if proven true, would "clear[ly]" violate

[54] "Subject to the provisions of this Act, the Administrator is authorized to contract in accordance with section 2(f) of the Bonneville Project Act of 1937 (16 U.S.C. 832a(f)). Other provisions of law applicable to such contracts on the effective date of this Act shall continue to be applicable." 16 U.S.C. § 839f(a).

> the cooperative's statutory duty under Tennessee law to provide its "members with electricity 'at the lowest cost consistent with sound business principles.' " *Id.* at 410 (citing Tenn. Code Ann. § 65-25-203).

PNGC II, 835 F.3d at 838 (emphasis added). BPA does not operate under a statutory duty to provide its customers with electricity at the lowest cost consistent with sound business principles, such that every facet of its business is reviewable under that standard. It operates under responsibilities to *set rates* as low as possible consistent with sound business principles, to *timely implement* the Northwest Power Act in a sound and business-like fashion, to *exercise its section 2(f) and 9(a) authorities* in a business-like manner, and to market some power in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles. See also, section 2(4) of the Act, ("to provide that the customers of the Bonneville Power Administration and their consumers continue to pay all costs necessary to produce, transmit, and conserve resources to meet the region's electric power requirements, including the amortization on a current basis of the Federal investment in the Federal Columbia River Power System"). None of the foregoing, however, can be read to mean that BPA may not take a discretionary action, such as serving DSI load, if that would increase other customers' costs. This is not how the standard has ever been applied and is not how it was ever intended to be applied. In short, the Court appears to have turned the standard on its head so that it now shackles BPA and is a basis for constraining agency flexibility rather than expanding it, as was Congress's original intent.

However, regardless of these concerns and arguments, BPA must ensure its Block Contract with Alcoa is consistent with *PNGC II*.

VII. REGIONAL JOB IMPACTS AND COST CAPS

a. Cost Caps

If service were to be provided to Alcoa for a Second Period, which requires the court to modify the Equivalent Benefits test, at a forecasted cost matching the maximum allowable under the Cost Caps, and if it were to be served at a weighted average annual IP rate linked to BPA's Tier 1 PF rate forecasted to be $38.22 per MWh, a cost of only $60 million per year, or $300 million for the entire Second Period, would be borne by the preference customers. (*See* Table 2 of Exhibit B in the Block Contract) Using the traditional yardstick that $60 million in cost per year translates into a one mill per kWh impact in the PF rate, the PF rate would increase by approximately one mill per kWh. That is a modest and tolerable rate increase, and one that BPA believes is reasonable given the tangible and intangible benefits of continued DSI service, as discussed in this ROD. We project that even with such an increase, the Tier 1 PF rate will be no more than 4% greater (and lower under an expected case) than they otherwise would be as a result of service to the DSIs (all other things being equal), a level that continues to assure preference customers very substantial system benefits. The PF rate would still be substantially below expected market rates.

Responding to extensive comments discussed and rationale detailed in Part IV, section (e) of this Record of Decision, Cost Caps will apply only to BPA's evaluation of whether it will provide service under the Block Contract during the Transition and Second Periods. That said, it is important to note that in response to comments on the Term Sheet (*See e.g.* PPC at 1, August 3, 2009), $300 million Cost Cap in the Second Period (see Exhibit B of the Block Contract) was reduced relative to the $350 million Cost Cap for the similar period in Term Sheet posted July 17, 2009. Reducing the proposed reduction in the Contract Demand from 390 aMW in the Original Contract to 320 aMW discussed immediately below also contributed to this decision.

b. Reduction in Quantity

As discussed above, the 320 aMW contract demand is a reduction relative to the 390 aMW available to it in the Subscription Contract and even higher amounts available under previous contracts. On the other hand, it is more than the 240 aMW offer in the December Draft Contract. *See also* Parts III and IV of this Record of Decision. That said, what is important is that the 320 aMW level supports Alcoa efforts to operate the Intalco Plant under a diversity of aluminum price environment (*see* Alcoa at 1, June 22, 2009), but also reduced the risks to BPA and its other customers when done in combination with the $50 million reduction in the Cost Cap for the Second Period discussed above.

c. Term Reduced from 17 to 7-years

In the lead-up to the December Draft Contract, Snohomish encouraged BPA to reduce the term length to mitigate risks. See Snohomish in MOU080610 at 2. We took this under consideration in releasing our Term Sheet and shortened the term from 17-years under consideration in the December Draft Contract to 7 years in the Term Sheet. This allows the costs and risks BPA and its customers may be exposed to in the future as it relates to DSI service to be considered more contemporaneously with future contract offers for DSI service, if any. BPA decision to have a seven year term for the Block Contract is also discussed in section IV(d) of the ROD.

d. Socio-Economic Implications

In determining whether to offer DSI power service, the Administrator also considered the regional economy and the potential for net positive employment. He did so because, as the Court has concluded, the agency has discretion whether to offer contracts to the DSIs. Operating within the confines of the law, as interpreted by the Court, the Administrator believes this discretion should be used in the context of whether it promotes public benefits, including such issues as job impacts.

A large number of comments were supportive in this regard. U.S. Senators Murray and Cantwell, along with Representatives Larsen and Inslee, representing the State of Washington, offered the following comments:

> We also appreciate BPA's efforts to continue negotiating long term contracts with the direct service industries (DSIs). While we realize the legal complexities around this issue, we believe this modified draft contract will give Alcoa, Inc. an opportunity to continue operations and keep over 500 family-wage jobs in Whatcom County.
>
> According to recent studies, aluminum companies make a positive contribution to Washington state's economy, in particular by providing family-wage jobs. The Intalco smelter opened its doors in 1966 and is currently one of the top employers in Whatcom County, with over 500 workers. With high unemployment levels across the region, and while our country continues to face tough economic times every job is valuable.
>
> We have worked for decades across state borders and political parties to protect the value of our low cost federal power system for everyone in the region and to distribute those benefits as widely as possible within the confines of the law.

Washington Governor Christine Gregoire offered similar sentiments:

> I know you understand the importance of this issue to the state. There are over 500 family-wage jobs at stake, jobs that are essential to our ability to make it through and recover from this recession. The Intalco facility is critical to the health of the local communities and to the economic health of this depressed area of the state.
>
> In our view, the proposed power contract readily meets your statutory requirement to ensure sound business principles. The contract secures the benefits of ongoing employment, provides certainty of future power demand, and offers clear benefits to the transmission system. The proposed power reserves provide the flexibility needed to integrate intermittent renewable energy sources such as wind—a high priority for our state. The two phases provide sufficient flexibility to resolve and meet the requirements of the court.

See also, comments of Washington State Senator Kevin Ranker ("I remain baffled by the fact that this original BPA customer continues to be singled out and treated inequitably compared to other customers of this federally owned power system"); Whatcom County Executive Pete Kremen ("Intalco's presence contributes far more than economic stability; it is an important thread of the social fabric of this community"); and dozens of supportive comments from Intalco employees, citizens of Whatcom County; and local businesses.

Despite these expressions of legitimate concern over the economic well-being of the region, public preference groups have attempted to use the Administrators' responsiveness as a means of impugning BPA's motivations and undermining its legal analysis. PPC, for example, posits that the Administrator's long-standing commitment to preserving regional jobs is evidence the contract is not based on sound business principles. PPC goes on to make an even more startling accusation: "[BPA's] October 30th letter, as well as the contract itself, indicates that one of the main reasons for which BPA is proposing to enter the deal is to continue to try to advance its policy goal of prioritizing smelter jobs over other jobs in the region." WPAG strikes a similar note, arguing that BPA is using the same justification that has already been discredited by the Court: "BPA is again arguing that it has the authority to offer the proposed Agreement because it strikes a reasonable balance between the rate impacts to its other customers and keeping the Alcoa smelter in operation in order to save family wage jobs in the region." (1) citing Burns October 30 Letter, p. 1**.** ICNU joins this chorus as well, announcing, apparently that the Court has ordered the Administrator to desist from any consideration of the health of the regional economy: "Once again, BPA is relying upon a rationale inconsistent with the 9th Circuit's decision to justify the new Alcoa contract [i.e., strike a balance between minimizing impacts to BPA rates and providing the direct service industries (DSIs) a chance to continue operating in the Pacific Northwest]." (2)

Such statements suggest that the Administrator does not understand that his policies in this connection do not, in and of themselves, provide legal justification for the proposed contracts. As this ROD itself attests, the Administrator is keenly aware that the Court has determined that saving regional jobs is not an adequate legal justification for offering service to a DSI customer. He is cognizant of the fact that the Court has found that such a determination must be predicated on sound business principles, as articulated by the Court. However, the Administrator does not understand the Court to have issued a gag order that would foreclose the Administrator from even speaking about his concerns about employment in the Pacific Northwest. Nor does the Administrator believe that the Court has imposed a standard so strict, and so out of touch with reality, that the Administrator cannot, in a Record of Decision, public announcements, or in court pleadings, that speak to the socio-economic issues that are influenced by the decisions he makes.

We understand that the Court has ruled that BPA cannot use net job impacts as the legal justification for offering Alcoa a contract. BPA is not using that logic in this ROD. BPA does not agree with the Court that public benefits, such as employment impacts, should not be considered, but for purposes of this decision, has conformed its practices and analysis to the Court's conclusion.

In this ROD, BPA has made the case for continued DSI service within the confines of the Court's opinions. The Administrator fully intends, to exercise discretion where it is available to seek to implement good public policy. Further, he will continue to develop policies that he believes are the right policies from a public interest standpoint, rather than considering only a limited set of interests. If the Administrator did not believe that the proposed contract was sustainable under the Court's newly-announced standard, he would not offer it under any circumstances. If he believed, however, that the contract did not promote sound policy goals, he would certainly be less inclined to offer it, even if the legal sustainability of the proposal was essentially a "slam dunk."

Expressing the Administrator's policy concerns and goals is not a license for PPC and others to argue that the entire legal predicate for providing DSI service is fatally flawed at the outset. Responding to legitimate concerns expressed in public comments which are not completely aligned with public power does not undercut the legal and economic analysis developed by BPA in response to the Court's opinion, even if such concerns do not, in and of themselves, provide the legal basis for the Administrator's decision.

More specifically, the Administrator does not, as PPC suggests, have a "policy goal of prioritizing smelter jobs over other jobs in the region." (3) BPA's position has been clear in this regard for many years now. The Administrator believes that the agency should do what it can, within the bounds of the law, to provide service to smelters in a manner that promotes, but does not guarantee, their continuing survival and only if the result is a likely public benefit such as a net positive employment impact. To be clear, that is not BPA's legal justification, but rather the policy setting for providing a legally sustainable contract. That is why, in light of the *PNGC* opinions, BPA determined in this instance to offer firm power service only for a seventeen month period during which it can be shown that the benefits of providing such service equal or exceed the costs. BPA does not believe the Equivalent Benefits Test should be the only means of providing service to Alcoa, but unless and until there is more clarity concerning legal requirements, BPA stands by its equivalent benefits analysis.

As to the economics of the transaction, BPA's analysis shows that continuing service to Alcoa via the Block Contract, within the Cost Cap levels specified in Exhibit B, will result in net positive gains in employment. The following discussion summarizes BPA's use of the 2006 *Regional Employment and Economic Study* to contemplate the 7-year Block Contract power sale contract that makes available physical service at the IP rate for up to 2-potlines at the Intalco facility and why we believe that it remains an indicator that moving forward with this contract should yield a small, positive economic benefit to the region.

The study evaluated four alternatives representing different delivery mechanisms and levels of benefits for the two aluminum smelters:

> Alternative 1 – No benefits; meaning that BPA would not offer power sales to the DSIs
>
> Alternative 2 – Financial benefits based on up to 560 average megawatts (aMW) capped at $59 million of net annual benefits.
>
> Alternative 3b – Up to 560 aMW at BPA's industrial preference (IP) rate
>
> Alternative 4 – Up to 560 aMW at BPA's priority firm (PF) rate.

Alternative 1 has no adverse impact on BPA's other customers. Alternative 2 capped the rate impact on BPA's other customers at $59 million – the equivalent of a $1.00 per MWh change in the PF power rate. Under this alternative, the regional economic study indicated a long-term net gain in employment between 95 and 1,232 jobs, considering a loss of up to 1,110 jobs in non-DSI related sectors, and a gain of up to 2,342 jobs at the smelters and in related sectors.[55] Alternatives 3b and 4 were both evaluated using a BPA power rate of $31.50 per MWh.[56] Both of these alternatives represented power sales of up to 560 aMW. As illustrated in Table 18-A included here for reference, a range of uncapped, market-priced purchases to support these power sales was then used to calculate BPA's cost for providing this power to the DSIs:[57]

TABLE 18-A - Market Prices and BPA Exposure

Market Price ($ / MWh)	40	45	50	55	60	70
BPA Exposure ($ millions)	40	64	88	111	135	182

The study then concluded that the short-term "positive economic impact of DSI service is significantly reduced as market prices go up" for Alternatives 3b and 4, and illustrated how this exposure adversely affected non-DSI employment in Table 19.[58] Importantly, the authors then contemplated the long-term employment impact of Alternative 2 in Table 21. The indirect non-DSI employment impacts were constant as the price of electricity changed because of the capped nature of the exposure from DSI benefits under Alternative 2 on BPA's other customers.

It is important to understand that the value of the study to BPA was, and is, as an estimate of the potential regional employment impact if it were to offer new contracts to the DSIs. The economic assumptions were not intended to be absolutely predictive. However, the estimates continue to be instructive and help BPA make the decision to proceed or not proceed with a contract offer to the DSIs, including establishing the appropriate Cost Cap levels to support an outcome of expected potential net employment gains in the region.

This Block Contract does that by establishing cost caps for the purchase of power to supply the DSIs, including other provisions to limit BPA's financial exposure and requiring Alcoa to maintain jobs even during periods of curtailment. The contract also limits the amount of power BPA would supply to the DSI aluminum smelters to no more than 460 aMW (i.e., 320 aMW for Alcoa and 140 aMW for CFAC, even though CFAC has declined the current offer). These mechanisms – taken together – are designed to limit the exposure of BPA' s other customers to no more than $86 million per year in the last 5 years (i.e. $60 million for Alcoa plus $26 million for CFAC) – proportionately

[55] Regional Employment and Economic Study, William B. Beyers, Lloyd O'Carroll, Paul Sorensen, August 14, 2006, page 2.

[56] Regional Employment and Economic Study, William B. Beyers, Lloyd O'Carroll, Paul Sorensen, August 14, 2006, page 20.

[57] Regional Employment and Economic Study, William B. Beyers, Lloyd O'Carroll, Paul Sorensen, August 14, 2006, page 20. While the study indicated "not all of the 560 MW would be used", the BPA Exposure in Table 18-A is substantially equal to the difference of the Market Price less $31.50 per MWh, multiplied by 560 MW times 8,760 hours in a year (i.e. $41.7 million = (40-31.5) * 560 * 8760).

[58] Regional Employment and Economic Study, William B. Beyers, Lloyd O'Carroll, Paul Sorensen, August 14, 2006, page 21.

reflecting the $50 million reduction in Alcoa's cost cap to $300 million in the last 5 years of the contract.[59]

These Cost Cap limits on the exposure of BPA's other customers are in contrast to the $182 million exposure of Alternatives 3b and 4 at a $70 per MWh market price described in Table 18-A included above, and are more comparable to the capped nature of Alternative 2, but do so under a physical power sale. To further consider the potential regional economic impacts of such limits in a contract offer, BPA revised Table 21 (taken from the study and included below) by updating four inputs to be consistent with this contract and to reflect more contemporary economic analysis. First, the indirect non-DSI job loss was increased from 1,110 to 1,316 – proportional to the increase from the $59 million capped cost in Alternative 2 to Alcoa's $300 million cost limit for the Subsequent 5-year Period in this contract, respectively.[60] Second, the effective power rate in this contract is the IP rate which is now forecast to escalate from the $34.60 per MWh in fiscal year 2010 at 2.5% each year thereafter, as opposed to the market price of power purchases minus the $12 per MWh financial benefit contemplated in Alternative 2.[61] This updated IP rate forecast reflects the IP rate adopted in the WP-10 rate proceeding and results in a $2 per MWh reduction in the cost cap. Third, direct smelter employment was reduced to 528 jobs – or 2,640 job-years – to reflect minimum employment commitments during periods of 2-potline smelter curtailment operations possible in the Block contract for Alcoa.[62] Lastly, BPA employed the Primary Metals multiplier of 2.782 released by the State of Washington in May 2008 which is lower than 3.2 – the simple average of the high and low indirect employment multipliers (3.9 and 2.5, respectively) utilized in the regional economic study.[63] The combined effect of updating these assumptions to be consistent with this Block contract for Alcoa is illustrated by this revised Table 21:

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[59] Draft Power Sales Agreement with Alcoa, Bonneville Power Administration, August 19, 2009, page 3 of Exhibit B.

[60] Regional Employment and Economic Study, William B. Beyers, Lloyd O'Carroll, Paul Sorensen, August 14, 2006, page 2; Draft Power Sales Agreement with Alcoa, Bonneville Power Administration, August 19, 2009, page 3 of Exhibit B.

[61] Draft Power Sales Agreement with Alcoa, Bonneville Power Administration, August 19, 2009, page 3 of Exhibit B; and Regional Employment and Economic Study, William B. Beyers, Lloyd O'Carroll, Paul Sorensen, August 14, 2006, page 2.

[62] Draft Power Sales Agreement with Alcoa, Bonneville Power Administration, August 19, 2009, page 1 of Exhibit G.

[63] "2002 Washington State Input-Output (I-O) Study", State of Washington, Office of Financial Management, May 2008, page 15; and Regional Employment and Economic Study, William B. Beyers, Lloyd O'Carroll, Paul Sorensen, August 14, 2006, page 13.

TABLE 21 - Long Term Employment and Income Impact Alternative 2 [REVISED]							
Price of Electricity $/MWh (IP rate)	40	45	50	55	60	70	
Employment (job-years)							
Direct DSI	2,640	2,640	2,640				
Alcoa	2,640	2,640	2,640				**5 - YEAR**
CFAC	-	-	-				**JOBS ASSESSMENT**
Indirect DSI	4,704	4,704	4,704				
Indirect non-DSI	(5,640)	(5,640)	(5,640)				
Total	1,704	1,704	1,704				**NO CURTAILMENT**

As this revised Table 21 continues to indicate, BPA believes there is a small, genuine economic benefit to our region in the form of a net employment gain of up to 1,704 job-years – or 312 jobs – as a result of this contract. This is an increase relative to the net employment gain of up to 764 job-years – or 152 jobs – reflected in the jobs assessment released with the term sheet and is the result of the lower cost cap.

In addition, the Block contract reduces the cumulative length of curtailment in the last 5-years of the contract term from 24-months to 18-months and added Alcoa's commitment to provide at least 120 jobs over the duration of each curtailment. When combined with the lower cost cap, BPA's revision to Table 21 below indicates that net jobs would at least remain neutral to slightly positive under the assumption that Alcoa were to curtail its maximum amount for 18-months during the last 5-years of the proposed contract:

TABLE 21 - Long Term Employment and Income Impact Alternative 2 [REVISED]							
Price of Electricity $/MWh (IP rate)	40	45	50	55	60	70	
Employment (job-years)							
Direct DSI	2,028	2,028	2,028				
Alcoa	2,028	2,028	2,028				**5 - YEAR**
CFAC	-	-	-				**JOBS ASSESSMENT**
Indirect DSI	3,613	3,613	3,613				**1.5 - YEAR CURTAILMENT**
Indirect non-DSI	(5,640)	(5,640)	(5,640)				**120 jobs during curtailment**
Total	1	1	1				

There is also potential for the net gain in regional employment to approach 1,500 jobs – or 7,000 job-years – if BPA and Columbia Falls Aluminum Company come to agreement on principles for a long-term power sales contract, Alcoa returns to its October 2008 employment level of 660 workers at Intalco and BPA is able to purchase power at a $52 per MWh forward price, which is $6 per MWh below the reduced per unit cost caps in this draft contract, thereby reducing the costs borne by its other customers by $25 million per year and mitigating the Indirect non-DSI employment impact. The combined effect of these events is illustrated in BPA's revision to Table 21 below:

TABLE 21 - Long Term Employment and Income Impact Alternative 2 [REVISED]						
Price of Electricity $/MWh (IP rate)	40	45	50	55	60	70
Employment (job-years)						
Direct DSI	4,455	4,455	3,300			
Alcoa	3,300	3,300	3,300			
CFAC	1,155	1,155	-			
Indirect DSI	7,938	7,938	5,880			
Indirect non-DSI	(5,640)	(5,640)	(3,948)			
Total	6,753	6,753	5,232			

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Based on the analysis just discussed, BPA has decided to execute the Block Contract with Alcoa, with Cost Caps as defined in Exhibit B. In addition to meeting the legal requirements as set forth by the Court, the Block Contract is expect to result in benefits to the region in the form of a small but positive net employment gain.

In addition, even if service were to be provided to Alcoa for a Second Period at a cost matching the maximum allowable under the Cost Caps, and if it were to be served at an IP rate linked to BPA's Tier 1 PF rate, a cost of only $60 million would be borne by preference customers. Using the traditional yardstick that $60 million in cost per year translates into a one mill per kWh impact in the PF rate, the PF rate would increase by approximately one mill per kWh.65 That is a modest and tolerable rate increase, and one that is well worth the cost given the tangible and intangible benefits of continued DSI service, as discussed in this ROD. We project that even with such an increase, the Tier 1 PF rate will be no more than 4% greater than they otherwise would be as a result of service to the DSIs (all other things being equal), a level that continues to assure preference customers very substantial system benefits. The PF rate would still be substantially below expected market rates.

VIII. PROCEDURAL AND OTHER ISSUES

a. Adequacy of Contract Review

Several parties raise a concern over the adequacy of the time allowed them to review and participate in the drafting of the Block Contract. Many complained that BPA provided insufficient information to evaluate the proposed transaction, that such information was not provided in a timely manner, that BPA's analysis should be subject to a hearing under section 7(i) of the Northwest Power Act, or requested that BPA meet with them to answer their questions with respect to the Block Contract. PPC at 2 (requesting meeting with BPA); NRU at 2 (requesting meeting with BPA); PNGC at 2 (requesting meeting with BPA); Snohomish at 1 (economic analysis not timely posted, too little time); SUB at 1-2, 7 (each of the foregoing complaints). WPAG echoed these concerns, claiming the contract was drafted in a closed process in a manner that conflicts with BPA's standard business practice, which has deprived BPA of the timely input of all but Alcoa, and that given the technically complex contract one week to review and comment was unreasonable. WPAG at 3-4.

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[64] If the Block Contract results in financial losses to BPA, there would be no rate impact to BPA's customers until at least October 2011. Rates are set for FY 2010-2011 and the probability of the cost recovery adjustment clause triggering in FY 2011 is near zero.

[65] As mentioned previously, the rates established in the WP-10 rate proceeding include approximately $38 million per year to address the costs and risk of industrial firm power service to the DSIs in FY10 and FY11. (*See* WP-10-FS-BPA-05A) A $60 million annual cost would represent an increase of $22 million over what is already included in the rates BPA has adopted. Such an increase would represent an increase of approximately one-third of one mill per kWh to the average annual PF rate of $27.22 per MWh, or less than 1.5%-percent.

BPA disagrees that there has been inadequate public review and participation in the drafting of the Block Contract. In situations where preference customers are negotiating contracts, there are many situations where there is broad alignment on the issues. There are some situations where that is not the case, but still it is appropriate to hear a variety of views. In such situations, it can make sense to conduct meetings that include a wider variety of interests. Negotiating with DSIs is a different matter, where BPA is dealing with a commercial customer rather than utility customers and there is no alignment of interests that would counsel broader participation. Moreover, given the contentious positions adopted by most preference customers, it is unlikely that inclusion of preference customers in negotiations would lead to a more effective or more efficient negotiating process. In fact, BPA believes that the result would be quite the opposite. Therefore, BPA's approach of making draft contracts available for review and comment makes more sense. It should be noted that the public processes have included broader public meetings which allowed parties with very different points of view to freely voice their opinions to BPA executives. BPA's approach in this connection is sufficiently transparent and inclusive. BPA has considered comments on DSI service issues eight times over the course of the past two years.

As BPA and Alcoa have worked to develop a power service agreement there has been an ongoing public process to review the proposed agreements. As described in the Background section of this ROD, there has been a regular public process to review all draft contracts and to provide input on them. In PPC's November 9, 2009, comments it stated, "As you know, based on numerous comments and discussions we have had on this topic, PPC opposes any service the Direct Service (DSIs) that comes at the expense of the preference customers." PPC added a footnote which states that PPC and other parties have now submitted numerous comments to BPA on the topic of whether it should sign a long-term contract for service to the DSIs. PPC went on the incorporate by reference all of its previously submitted comments on the topic submitted over the past two years. Id. Similarly, WPAG states in its November 9, comments that this is the fourth time that the WPAG utilities have submitted comments to BPA on the proposed service. WPAG adds that the proposed Agreement is not new, but is essentially a repeat of the agreement upon which the WPAG utilities have previously commented. ICNU's November 9 comments also state that ICNU and BPA's preference customers have previously filed comments regarding the details of BPA's proposed agreements with Alcoa and CFAC. In response to comments that the Block Contract was negotiated behind closed doors and out of their view, it is BPA's practice to negotiate with private companies in a manner that respects and protects the business sensitive information those companies often divulge. This is unlike the public body, municipal, and cooperative utility customers that are consumer owned and operated in a manner open to the public. Once BPA and a DSI customer, like Alcoa, have reached terms the Administrator believes are reasonable they are brought into the open for review and comment by the public. As such, BPA acts in a sound and reasonable business-like manner.

Given the request by its public customers to meet with them to discuss the draft Block Contract, BPA's Deputy Administrator and other BPA staff met with several preference customers at the offices of the PPC on November 3, 2009. The prepared materials that BPA presented at this meeting are attached hereto. Attachment G. As further noted by PNGC in its comments of November 9, 2009, "BPA has met with its consumer-owned utility customers and discussed the assumptions and resulting forecasts in conjunction with actual market prices for the proposed agreements." With respect to the amount of time allowed for comments, BPA can only note that it provided adequate time given that these issues have been thoroughly discussed in the past. BPA is mindful that the development of the Block Contract has been ongoing for over a year, which has included several public meetings and opportunities for review and comment on proposed service alternatives. Given the relatively straight-forward nature of the Block Contract and BPA's economic analysis, BPA believes customers had sufficient time to carefully evaluate the contract and BPA's analysis, and that this fact is evidenced in the generally high quality of comments received.

SUB commented that BPA's analysis of the Block Contract is subject to a section 7(i) hearing under the Northwest Power Act, or that it must be subjected to the same level of scrutiny associated with a section 7(i) hearing. SUB at 7. This is incorrect. A decision to offer a contract for the sale of power under section 5 of the NWPA is not a proposal to set wholesale power rates under section 7 of the act. BPA's analysis of the economic effect of a proposed contract is clearly not subject to a section 7(i) rate hearing, since BPA is not establishing rates in the Block Contract, nor could it. SUB cryptically suggests BPA is "decoupling" its forecast of benefits under the Block Contract from "the WP-07 rate setting process which includes a number of components – including loads and risks." SUB at 7. SUB appears to be suggesting that any contract BPA proposes to execute during the term of a rate period requires BPA to re-open its rate proceeding to reconcile the rate impacts of the contract to BPA's rate case final decisions with respect to, among other things, "loads and risks." Id. In simplest terms, BPA sets its rates to recover its forecast costs over the term of the rate period. As noted, BPA allocated $37 million in forecast costs to its base rates to serve DSI load in the WP-10 rate proceeding, which covers the term of the Block Contract. That is not to say, as is suggested by SUB, that any proposed action by BPA within the WP-10 rate period that could result in BPA incurring costs not expressly contemplated in the rate case requires BPA to re-open that rate case; such costs, if incurred, would be paid for through cash reserves, planned net revenues for risk, or other risk mitigation tools such as the cost recovery adjustment clause.

In sum, a section 7(i) proceeding is required only to set BPA's rates for power and transmission service. The applicable charge for power sold under the contract is the IP 10 rate, which BPA established in the WP-10 Wholesale Power Rate Proceeding. BPA is not changing or modifying that rate as a part of the transaction. There is no other rate involved. Therefore, a 7(i) proceeding is not required.

b. Sequencing of *PNGC I* Remand

PPC argues "BPA cannot plausibly argue that any exigent circumstances compel this cart-before-the-horse approach, since BPA's own analysis shows that Alcoa should be basically indifferent to whether BPA offers the 19-month sale or not." (6) PPC goes on to say "Once BPA concludes that process [the lookback] it will be required to seek repayment from Alcoa. It would be odd indeed for BPA to agree to forego a contractual provision guaranteeing such a payment by Alcoa." SUB commented in an earlier process that BPA must resolve any lookback amounts owing by the DSIs, including Alcoa, associated with the Court's remand in *PNGC I*. *See* SUB comments dated September 9, 2009, regarding "Draft Seven-Year Agreements: Alcoa & Columbia Falls Aluminum Company", at 6. BPA believes that final decisions by BPA in connection with that remand are unrelated to BPA's decision to enter into the Block Contract, and that nothing in the Block Contract precludes BPA from seeking restitution from Alcoa in connection with the remand if, in fact, that is the outcome on remand, or in later raising rates to Alcoa to effect such restitution. Final resolution, including judicial review, of the issues on remand in *PNGC I* are likely to be contentious and time consuming, and BPA sees no good reason to delay entering into a new Block Contract with Alcoa until that process is completed.

c. BPA's exposure to market purchases in excess of the IP rate

NRU suggests that there should be a check-in half way through the term of this contract to determine whether the contract is still in the money. If it is not, then an adjustment should be made to the IP rate so that the IP rate as applied to the Alcoa and CFAC loads will generate more revenues than BPA would have obtained through market sales of power. *See* NRU in ALC090151 at 1.

NRU's proposal would fundamentally deprive Alcoa of the benefit of its bargain, and is commercially unreasonable. Not only is NRU's proposal unfair, it is also unnecessary. Alcoa has agreed to purchase power from BPA at the IP rate, which is set to recover BPA's cost. On average the IP rate for a substantial portion of the Initial Period of the Block Contract is above BPA's existing forecast of market prices. Certainly, Alcoa has its own reasons for entering into this transaction, and presumably believes purchasing from BPA, even at a small premium to market, is in its own best interests. If market prices fall lower than forecast by BPA, Alcoa is locked into paying the IP rate which would be that much higher as compared to market. If market prices rise above the IP rate, it is commercially unreasonable that Alcoa would also face the possibility of an adjustment to the IP rate to, as NRU proposes, "generate more revenues than BPA would have obtained through market sales of power." Therefore, BPA does not find this to be a reasonable or business-like proposition, or one that is required by the Court.

d. Loss of Money to Benefit the DSIs

In its November 9, 2009 comments PPC states that the contract is founded on the notion that BPA will incur losses in order to benefit the DSIs, at the expense of BPA's preference customers. PPC at 3. PPC asserts that the only rational reason Alcoa would want to purchase power at the IP rate is if it perceives that BPA's IP rate will be below the market in which it can unload its power, the same market into which BPA could sell the power if it were not selling to Alcoa. *Id.*

BPA is not privy to Alcoa's internal business reasons for why it decided to enter into the Block Contract. Whether or not Alcoa will remarket any other power supply is within its discretion and does not preclude BPA from marketing industrial firm power to Alcoa at the IP rate. Such a decision by Alcoa to remarket its own power does not affect the IP rate that will apply to sales of industrial firm power. Assuming, as PPC asserts, that Alcoa decides to unload its power into the market, then it is Alcoa that is taking on the risk of the market and its volatile prices, as it seeks to cover its power costs. BPA, on the other hand, will achieve revenue certainty through its IP rate.

BPA understands that Alcoa has reasons for desiring a long term contract with BPA that go beyond the vagaries of the real time market. A long term contract with BPA provides some degree of price stability that cannot be achieved purchasing in the real time markets. For example, Alcoa can use long term stability in connection with hedging transactions in the aluminum market. A longer term power supply also provides a planning horizon sufficient to allow Alcoa to determine the viability of making capital improvements in the plant itself. *See* Alcoa in DSL090057 at 2.

e. Relationship to BPA's Financial Plan

Springfield Utility Board raised two issues regarding the relationship of the Block Contract and BPA's Financial Plan. First, SUB argues that the proposed contract violates the Good Year/Bad Year (GY/BY) section of the Financial Plan published in January 2008. Second, Springfield Utility Board argues that the Financial Plan implies that the "cost of providing service to DSI's can create volatility . . . and that DSI's can have a significant effect on BPA's costs and risks." SUB in ALC090155 at 8.

Specifically, SUB argues that the proposed contract is a specific Good Year/Bad Year plan of action that should be addressed in a rate case 7(i) process. SUB argues that the proposed contract violates the GY/BY standards outlined in the Financial Plan in that the proposed metric differs from those discussed in the plan, that the proposed metric is complex, unfamiliar and not well understood in the utility and business communities, and that it is biased and obscures tradeoffs between customer groups. SUB at 8.

SUB misinterprets the stated intent of the GY/BY chapter of the Financial Plan, which is to "identify potential alternatives courses of action, propose a framework for comparing them, and discuss the trade-offs between various options." BPA Financial Plan, January 2008, at 23. The Plan also notes that "the purpose of this Good Year and Bad Year planning effort is to generate, document, and begin evaluating issues and possible actions BPA might consider taking over the long term." *Id.* at 26. Finally, the Plan states that "the purpose of the Financial Plan is not [emphasis added] to produce a detailed Good Year/Bad Year plan with specific metrics, thresholds, and detailed courses of action." *Id.* at 30. In other words, the GY/BY chapter is no more than a conceptual discussion of the subject rather than a specific plan. This makes it difficult to violate the terms of a plan as alleged by SUB if a plan does not exist.

SUB also mistakenly interprets the DSI contract as a GY/BY plan. BPA's Financial Plan views such a plan as a tool that allows BPA to take advantage of the opportunities afforded by better than expected financial results or, conversely, to adapt to the changes created by worse than expected results. *Id.* at 23. For example, the different metrics for assessing whether a year is good or bad focus on the target for a specific year. The possible actions available depending on the financial circumstances are actions taken in the year being assessed, in the case of a bad year, or in the following year, in the case of a good year. *Id.* at 26-29. The Block Contract does not propose a similar construct.

Finally, assuming that the Block Contract is a GY/BY plan, SUB mistakenly assumes that the Financial Plan requires the contract to be addressed in a rate case 7(i) process. SUB at 8. While the Financial Plan does state that a detailed GY/BY plan would be addressed in a rate case, BPA reserved the right "to pursue any of these actions if circumstances warrant it, based on continued internal analysis and discussion with BPA's stakeholders." BPA Financial Plan, January 2008, at 30. If this contract is truly a GY/BY plan, BPA may implement it without using a 7(i) process because BPA has conducted the internal analysis and has given stakeholders opportunity for discussion and involvement.

In addition, in a discussion of the evolving nature of BPA's risk profile, the Financial Risk Metrics section of the Financial Plan states that sales to aluminum smelters as so small today that they have little effect on BPA's sales revenues. Plan at 9. SUB also argues that the Financial Plan infers that "the cost of providing service can create volatility." SUB at 8. This interpretation reads a great deal into a very plain statement about aluminum smelters. The Financial Plan is completely silent on how the variability of costs related to DSI service can affect BPA. The only statement about DSI's in the Plan is the one referenced at the beginning of this paragraph and it only notes that sales variability has declined dramatically since the publication of BPA's 10-year Financial Plan in 1993. For the forgoing reasons, the Block Contract does not violate the Financial Plan.

f. BPA has not allocated Equivalent Benefits to any customers

SUB questions whether allocating all benefits to DSIs is consistent with the aim of the DDC to allocate good financial outcomes to customers. SUB at 12. BPA does not entirely understand SUB's statement BPA has allocated all of the benefits to the DSIs and its conclusion that there should be some kind of DDC impact. As noted in BPA's WP-10 rates ROD, "[t]he aggregate impacts of risks on reserves are used to calculate TPP and therefore PNRR during rate cases; after the conclusion of a rate case, further aggregate changes to reserves can result in the triggering of a CRAC or DDC." WP-10-A-02 / TR-10-A-02, Chapter 7 (Risk Analysis and Mitigation) at 45. BPA has assigned a monetary value to benefits received by making the sale to Alcoa. BPA has not allocated those benefits to any customers at this time because they will not actually accrue until the contract is performed. BPA does not believe that type of prospective financial outcome that should contribute to triggering the DDC. However, this type is a ratemaking issue and it would be more appropriate for discussion during a section 7(i) rate proceeding.

IX. ENVIRONMENTAL EFFECTS

a. NEPA Evaluation

BPA has reviewed the proposed block power sales 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. Based on this review, BPA has determined 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. More specifically, this contract fall 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." The Environmental Clearance Memorandum that documents this categorical exclusion for the contract has been posted at BPA's website at:
http://www.efw.bpa.gov/environmental_services/categoricalexclusions.aspx.

b. Comments on Environmental Effects

During the public comment period for the proposed Block Contract, BPA received comments from two entities – Canby Utility Board and Springfield Utility Board – that raised issues concerning the NEPA process for the Block Contract. The following identifies these issues and provides responses.

EIS is not Necessary

SUB argues that BPA should prepare a new Environmental Impact Statement (EIS) before entering into the Block Contract. SUB at 17.

Under NEPA, EISs are required for proposed major federal actions – i.e., those proposed actions with the potential for a significant environmental impact. Accordingly, if a proposed action would not have the potential for a significant environmental impact, no EIS is required. Furthermore, an EIS is not required where the federal action maintains the environmental status quo.

As explained above, BPA has reviewed the Block Contract under NEPA and determined that the federal action of continuing to supply power, whether in monetized form or any actual power transfer, would not have the potential for a significant environmental effect. BPA expects to supply power to Alcoa's Intalco Plant from existing generation sources, and these sources would be expected to continue to operate within their normal operating limits. This power would be supplied to the Intalco Plant over existing transmission lines that connect the existing Intalco Plant to BPA's electrical transmission system, and no physical changes to this system would occur. In addition, the Block Contract would not cause a change in the Intalco Plant's existing operations in such a way that environmental impacts would significantly differ from the currently existing situation. Therefore, BPA has appropriately prepared a Categorical Exclusion for the proposal to continue power sales to Alcoa, and an EIS is not necessary.

No Change in Environment Impacts

Canby argues that BPA should analyze environmental impacts that may occur from purchases of power needed to fulfill the Block Contract. Canby at 11.

As indicated above, BPA expects to provide power to Alcoa from existing generation sources that would continue to operate within their normal operating limits. As such, there would be no change in any environmental impacts associated with implementation of the Block Contract with Alcoa. If BPA is not able to obtain power to fulfill its obligations under the Block Contract from only existing generation sources operating within their normal operating limits (either through market purchases or from a specific resource), BPA would review the proposed power acquisition under NEPA and conduct additional NEPA evaluation, as appropriate, for the proposed acquisition, once more information is known about the nature, type, and source of the acquisition. BPA also will prepare additional NEPA documentation as necessary prior to making such an acquisition.

Business Plan EIS Is Not Relevant to this Decision

Canby also asserts that the Block Contract appears to be inconsistent with the Market-Driven Alternative that was analyzed in BPA's Business Plan Final EIS (DOE/EIS-0183, June 1995) and adopted by BPA in the Business Plan Record of Decision (ROD, August 1995). Canby at 11.

Because BPA is not basing its decision to enter into the Block Contract on the Business Plan EIS and ROD, these documents are not relevant to this decision. As discussed above, BPA has prepared a Categorical Exclusion for this decision, which is appropriate given the nature of BPA's action under the Block Contract.

X. CONCLUSION

For the foregoing reasons, BPA has signed the Block Contract on the date of this record of decision.

Issued at Portland, Oregon, this 21st day of December, 2009.

____/s/ Stephen J. Wright ________________
Stephen J. Wright
Administrator and Chief Executive Officer

Attachment F

Contract No. 06PB-11744, Power Sale to Alcoa, Inc. (June 2006)

Contract No. 06PB-11744

BLOCK POWER SALES AGREEMENT
executed by the
BONNEVILLE POWER ADMINISTRATION
and
ALCOA INC.
and
PUBLIC UTILITY DISTRICT NO. 1 OF WHATCOM COUNTY, WASHINGTON

AUTHENTICATED

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This BLOCK POWER SALES AGREEMENT (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA), Alcoa Inc. (Alcoa), and Public Utility

District No. 1 of Whatcom County, Washington (Whatcom). Alcoa is a corporation organized under the laws of the State of Pennsylvania. Whatcom is a public utility district organized under the laws of the State of Washington. BPA, Alcoa, and Whatcom are sometimes referred to in the singular as "Party" or in the plural as "Parties."

RECITALS

On June 30, 2005, BPA issued a record of decision titled "Bonneville Power Administration's Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011." On May 31, 2006, BPA issued a supplement to the record of decision. The record of decision and its supplement together constitute and are referred to herein as the Administrator's ROD.

This Agreement implements the decisions contained in the Administrator's ROD.

BPA has administratively divided its organization into two business lines in order to functionally separate the administration and decision making activities of BPA's power business from the administrative and decision making activities of its transmission business. References in this Agreement to the Power Business Line (PBL) are solely for the purpose of establishing which BPA business line is responsible for the administration of this Agreement.

BPA, Alcoa and Whatcom agree:

1. TERM

This Agreement, when signed by the Parties, shall become effective on October 1, 2006, and shall continue in effect through September 30, 2011, unless terminated earlier pursuant to section 16 below. All obligations incurred hereunder shall be preserved until satisfied.

2. DEFINITIONS

Capitalized terms in this Agreement shall have the meanings defined below, in the exhibits or in context. All other capitalized terms and acronyms are defined in BPA's applicable Wholesale Power Rate Schedule(s), including the General Rate Schedule Provisions (GRSPs).

(a) "Business Day" means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principle place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

(b) "Contract Year" or "CY" means the period that begins each October 1 and which ends the following September 30. For instance, CY 2007 begins October 1, 2006, and continues through September 30, 2007.

(c) "Demand Entitlement" means, during periods when this Agreement operates as a physical Surplus Firm Power sale, the megawatt (MW) amount each hour that Whatcom shall purchase from PBL, and that Alcoa shall purchase from Whatcom, as specified in Exhibit E.

(d) "Equivalent PF" means the applicable average Priority Firm Rate at 100 percent load factor, as determined pursuant to Exhibit F.

(e) "Escrow Account" means the specific account established pursuant to the provisions in section 9(b) below for receipt of funds from BPA and transfer of funds by Whatcom to Alcoa.

(f) "Forecast Market Price" means the annual forecast market price for power at 100 percent load factor, as determined pursuant to the procedures in Exhibit F or, if Alcoa has selected an option pursuant to subsection 5(c) or subsections 5(c) and 5(d), then as determined by the average purchase price paid by Alcoa during the Option Period.

(g) "FY 07-09 Rate Period" means the wholesale power rate period that begins on October 1, 2006, and continues through September 30, 2009.

(h) "FY 10-11 Rate Period" means the wholesale power rate period that begins on October 1, 2009, and continues through September 30, 2011.

(i) "MB Monthly Payment" means the monthly Monetary Benefit payment that is available during each month, as calculated in section 6(c)(4) below.

(j) "MB Rate" means the rate in dollars per megawatt-hour ($/MWh) used to calculate MB Monthly Payments pursuant to section 6(c) below. The MB Rate is determined by subtracting Equivalent PF from Forecast Market Price, and shall not exceed $24/MWh.

(k) "Maximum Allocation" means, for the purpose of determining MB Monthly Payments, the maximum average megawatt (aMW) amount that may be used to determine a MB Monthly Payment. The Maximum Allocation is shown in Exhibit E.

(l) "Maximum MB Monthly Payment" means the amount calculated in section 6(c)(3) below.

(m) "Minimum Allocation" means, for the purpose of determining MB Monthly Payments, the minimum aMW amount that may be used to determine a MB Monthly Payment. The Minimum Allocation is equal to one-fourth of the Maximum Allocation.

(n) "Monetary Benefits" means monetary payments made by BPA to Whatcom for the account of Alcoa under this Agreement, as determined pursuant to the provisions in section 6 below.

(o) “Monthly Plant Load” means a monthly aMW amount equal to the Total Plant Load for each month divided by the number of hours in each such month.

(p) “Monthly Purchase Deficiency” means the monthly amount(s) of Surplus Firm Power not purchased due to a curtailment, as such amount(s) may be adjusted pursuant to section 4(e)(1) below.

(q) “Northwest Power Act” means the Pacific Northwest Electric Power Planning and Conservation Act of 1980, P.L. 96-501.

(r) “Option Benefits” means the MB Monthly Payments under the options provided for in section 5(c) and 5(d), including UBA amounts if Alcoa chooses to establish Monetary Benefits pursuant to the provisions to include UBA in Option Benefits as specified in section 8(a)(4) below.

(s) “Option Period” means the combined period(s) of the option(s) specified in the provisions of section 5(c) and 5(d) selected by Alcoa to establish MB Monthly Payments

(t) “Other DSIs” means aluminum smelters other than Alcoa that have executed an agreement substantially in the form of this Agreement.

(u) “Points of Measurement” means the interconnection points between BPA, Alcoa, and other control areas, as applicable. Electric power amounts are established at these points based on metered amounts or scheduled amounts, as appropriate.

(v) "Point of Receipt" means the points of interconnection on the transmission provider's transmission system where Surplus Firm Power shall be made available by PBL to Whatcom, and where Surplus Firm Power shall be made available by Whatcom to Alcoa’s transmission provider.

(w) “Power Business Line” or “PBL” means that portion of the BPA organization or its successor that is responsible for the management and sale of BPA’s Federal power.

(x) “Region” means the definition established for “Region” in the Northwest Power Act.

(y) “Surplus Firm Power” means electric power that PBL shall make continuously available to Whatcom, and which Whatcom shall make continuously available to Alcoa, under this Agreement.

(z) “Total Plant Load” means the amount of electric energy in megawatt-hours (MWh) consumed during each month at Alcoa’s production facilities. A detailed description of Alcoa’s production facilities, including station service requirements and metering equipment, is described in Exhibit B.

(aa) "Transmission Business Line" or "TBL" means that portion of the BPA organization or its successor that is responsible for the management and sale of transmission service on the Federal Columbia River Transmission System (FCRTS).

(bb) "Unused Benefit Amount" or "UBA" means either: (1) an aMW amount determined pursuant to section 7(a) during any period in which Monetary Benefits are provided, or (2) a MW amount determined pursuant to section 7(b) during any period in which this Agreement operates as a physical Surplus Firm Power sale.

3. APPLICABLE RATES

(a) **Applicable Rate for Purchases by Whatcom**
Purchases by Whatcom under this Agreement are subject to the Firm Power Products and Services (FPS) rate schedule or its successor, and the General Rate Schedule Provisions (GRSP). Purchases under the FPS rate schedule are established as follows:

If this Agreement operates as a physically delivered Surplus Firm Power sale pursuant to section 4 below, then section 4(a) below and Exhibit A, Surplus Firm Power Rate, identify Surplus Firm Power amounts, rates, and billing entitlements subject to the FPS rate schedule. If the Surplus Firm Power sale is monetized, then the provisions of section 6 below establish the applicable FPS rate.

(b) **Applicable Rate for Purchases by Alcoa**
Purchases by Alcoa under this Agreement are subject to the applicable rate schedule developed by Whatcom for such purchases. The rates and billing entitlements specified in such rate schedule shall be equal to those rates billed to Whatcom by BPA under this Agreement, FPS rate schedule and GRSPs, as specified in Exhibit A.

4. POWER SALE PROVISIONS

This section 4 only applies when this Agreement operates as a physically delivered Surplus Firm Power sale. In this event, the Monetary Benefit provisions in section 6 shall not apply. All physically delivered Surplus Firm Power provided by PBL under this section 4 is solely for service to Total Plant Load.

(a) **Power Sale by PBL to Whatcom**

(1) **Hourly Amounts**
PBL shall make available and Whatcom shall purchase the Demand Entitlement each hour. The Demand Entitlement is specified in Exhibit E.

(2) **HLH and LLH Energy Entitlements and Demand Entitlement**

The Demand Entitlement multiplied by: (A) the number of HLH; and (B) the number of LLH in the applicable month establishes Whatcom's HLH and LLH Energy Entitlements with respect to this Agreement.

(b) **Power Sale by Whatcom to Alcoa**

(1) **Hourly Amounts**
Whatcom shall make available and Alcoa shall purchase the Demand Entitlement each hour. The Demand Entitlement is specified in Exhibit E.

(2) **HLH and LLH Energy Entitlements and Demand Entitlement**
The Demand Entitlement multiplied by: (A) the number of HLH; and (B) the number of LLH in the applicable month establishes Alcoa's HLH and LLH Energy Entitlements.

(c) **Unauthorized Increase Charge**
Alcoa shall not intentionally schedule in excess of the amount specified in section 4(b)(1) above. However, in the event that an excess amount is scheduled due to error, then such amounts taken by Alcoa from Whatcom at the Points of Receipt in excess of the amounts specified in section 4(b)(2) above shall be subject to the Unauthorized Increase Charge for demand and energy consistent with the applicable BPA Wholesale Power Rate Schedules and GRSPs, unless such power is provided under another contract with PBL. Power that has been provided for energy imbalance service pursuant to an agreement between TBL and Alcoa shall not be subject to an Unauthorized Increase Charge for Demand and Energy under this Agreement. Any Unauthorized Increase Charge shall be billed by BPA in accordance with the billing procedures described in section 9(a) below. Any Surplus Firm Power used by Whatcom or Alcoa for any other purpose shall be subject to the Unauthorized Increase Charge.

(d) **Curtailment**
If Alcoa curtails Total Plant Load in whole or in part, then Alcoa may request take-or-pay mitigation for purchases under section 4(b) above pursuant to section 4(e) below.

(e) **Take-or-Pay Mitigation for Curtailments**
If Alcoa chooses to curtail its purchase obligation, then the following terms and conditions shall apply:

(1) **Notice of Curtailment**
Alcoa shall provide written notice to PBL and Whatcom at least three (3) Business Days in advance of a curtailment. Such notice shall specify the monthly amounts of power to be curtailed and the duration of the curtailment. The election to curtail such power, and the amount and duration of such curtailment, may not be changed without PBL's consent. PBL's sale to Whatcom shall be reduced by the amount of power curtailed, and Whatcom shall not be assessed any damages or

incur any liability as a result of any such reduction. The Monthly Purchase Deficiency will be reduced by any reduction to the Demand Entitlement pursuant to section 7(b)(2) below.

(2) **Calculation of Damages**
Alcoa shall pay directly to BPA damages for each Monthly Purchase Deficiency equal to the amount by which the reasonable market value of such Monthly Purchase Deficiency is less than the price of the applicable rate specified in Exhibit A. For purposes of calculating damages under this section 4(e)(2), the Monthly Purchase Deficiency(s) shall be reduced by any reduction of Demand Entitlement under section 7(b)(3), effective on the date any such reduction becomes effective. No later than 60 days following the end of each Contract Year, PBL shall, for each month of the previous Contract Year, calculate the reasonable market value for each Monthly Purchase Deficiency during such Contract Year. Reasonable market value and calculation of damages shall be determined as follows.

(A) No later than 3 Business Days prior to the commencement of a curtailment under this section 4(e), Alcoa may obtain one or more transactable quotes for all or a portion of such power from a third party. The transactable quote may be for any length of time and curtailment amount. Each quote shall be deemed equal to the reasonable market value of such power to which the quote applies for the purpose of calculating damages under this section 4(e)(2). BPA may, but shall not be obligated to, resell the curtailed power to the third party, retain the power, or dispose of the power as it chooses. Alcoa shall allow PBL at least 4 hours during normal business hours to decide whether or not to transact under such quote.

(B) BPA shall determine, by any reasonable method, the reasonable market value of the portion of each Monthly Purchase Deficiency for which Alcoa has not obtained a transactable quote. The reasonable market value shall be adjusted to reflect volume and BPA transmission costs associated with remarketing each such portion of the Monthly Purchase Deficiency, regardless of whether each such portion is actually remarketed.

(C) BPA shall bill Alcoa and Alcoa shall directly pay BPA damages for such Contract Year equal to the amount by which the sum of the product of (1) each Monthly Purchase Deficiency and (2) the applicable rate specified in Exhibit A that BPA would have charged each month if the power had been taken under this Agreement, exceeds the sum of the product of (1) each Monthly Purchase Deficiency and (2) the reasonable market value in each month. Amounts for damages under section

4(e)(2)(A) and section 4(e)(2)(B) may only be netted within a Contract Year. If a transactable quote for a curtailment or portion of a curtailment extends into a future Contract Year, then the total amounts associated with such quote will be netted in the Contract Year in which the curtailment or portion of curtailment associated with such quote begins. BPA is not obligated to pay Alcoa the difference when the reasonable market value exceeds the applicable rate in Exhibit A.

It is expressly agreed to by the Parties that BPA shall not be obligated to enter into replacement transactions to determine or collect damages under this section 4(e)(2).

It is also expressly agreed that BPA will apply its then-current applicable credit policies if damages are due under this section 4(e)(2), and such policies may include an obligation to prepay for damages.

(f) **Scheduling**
All Surplus Firm Power transactions under this Agreement shall be scheduled and implemented consistent with Exhibit C, BPA Power Business Line Scheduling Provisions. The procedures for scheduling described in Exhibit C are the standard utility procedures followed by BPA for power transactions between PBL and other utilities or entities in the Region that require scheduling.

(g) **Delivery**

(1) **Transmission Service for Surplus Firm Power**
This Agreement does not provide transmission services for, or include the delivery of, Surplus Firm Power by BPA to Whatcom, or by Whatcom to Alcoa. Alcoa shall be responsible for executing one or more wheeling agreements with a transmission supplier for the delivery of Surplus Firm Power (Wheeling Agreement). PBL and Alcoa agree to take such actions as may be necessary to facilitate the delivery of Surplus Firm Power to Alcoa, consistent with the terms, notice, and the time limits contained in the Wheeling Agreement.

(2) **Liability for Delivery**
Alcoa waives any claims against PBL and Whatcom arising under this Agreement for nondelivery of power to any points beyond the applicable Points of Receipt. Neither Whatcom nor PBL shall be liable for any third-party claims related to the delivery of power after it leaves the Points of Receipt. In no event shall any Party be liable under this Agreement to any other Party for damage that results from any sudden, unexpected, changed, or abnormal electrical condition occurring in or on any electric system, regardless of ownership. These limitations on liability apply regardless of whether or not this Agreement provides for transfer service.

(3) **Points of Receipt**
PBL shall make Surplus Firm Power available to Whatcom, and Whatcom shall make Surplus Firm Power available to Alcoa under this Agreement at Points of Receipt solely for the purpose of Alcoa scheduling transmission to points of delivery for service to Alcoa's Total Plant Load. Alcoa shall schedule, if scheduling is necessary, such Surplus Firm Power solely for use by its Total Plant Load. PBL, for purposes of scheduling transmission for delivery under this Agreement, shall specify Points of Receipt in a written notice to Whatcom and Alcoa no later than October 1, 2008.

If required by the Wheeling Agreement, when PBL designates such Points of Receipt, PBL shall provide capacity amounts for transmission under the Wheeling Agreement associated with the initial Points of Receipt that can be accepted as firm Points of Receipt under Alcoa's Wheeling Agreement (except in the event that all Points of Receipt on the Federal Columbia River Power System (FCRPS) would be considered nonfirm). The sum of capacity amounts requested by PBL shall not exceed the amount of Surplus Firm Power specified in sections 4(a) and 4(b) above. Such Points of Receipt and their capacity amounts may only be changed through mutual agreement. However, at any time PBL may request the use of a nonfirm Point of Receipt to provide Surplus Firm Power to Whatcom for the account of Alcoa, but notwithstanding section 4(g)(2) above, PBL shall reimburse Alcoa for any additional costs or production losses incurred by Alcoa due to its compliance with such request.

(4) **Transmission Losses**
PBL shall provide Alcoa the transmission losses between the Points of Receipt and Alcoa's points of delivery for Surplus Firm Power, at no additional charge. Such losses shall be provided at Points of Receipt as established under section 4(g)(3) above, and under the terms and conditions as defined in the transmission provider's tariff.

(h) **Measurement**

(1) Amounts of Surplus Firm Power taken are deemed equal to the amount scheduled by Alcoa under section 4(f) above or an amount of power as measured at Points of Measurement, as appropriate.

(2) Alcoa shall provide reasonable notice to PBL and Whatcom prior to changing control areas.

(i) **Interruption Rights**
PBL shall have a one-time right during the term of this Agreement to interrupt deliveries of a portion of the Surplus Firm Power hereunder pursuant to the following provisions. PBL may interrupt a portion of Surplus Firm Power deliveries if PBL anticipates, in its sole and exclusive discretion, that average forward market prices for a flat block of power will exceed

$125/MWh during an interruption period to be specified by PBL in a written notice. In this event, PBL shall consult with Alcoa and Whatcom prior to providing such written notice. If PBL decides to interrupt, then it will provide 90 days advance written notice to Alcoa and Whatcom that specifies the amount of Surplus Firm Power to be interrupted and the associated interruption period; *provided, however,* that a minimum of 6 aMW will not be subject to any such interruption. Unless the Parties mutually agree otherwise, such interruption period shall extend for a minimum of 6 months and for a maximum of 12 months, regardless of the level of actual market prices during an interruption period. In the event of an interruption, BPA shall pay Whatcom, and Whatcom shall in turn pay Alcoa, $24/MWh for amounts interrupted. Payments shall be made pursuant to section 9(b) below. Payments to Alcoa under this section 4(i) shall be used first to compensate Alcoa's employees employed at the time of an interruption under this section 4(i) by providing each such employee, at the election of Alcoa, either (1) the opportunity to work a regular work week (40 hours) at regular wage and benefit rates, or (2) special supplemental benefits such that the employee's effective after-tax income (including any available unemployment income) will be equal to what the employee's income would have been working a regular work week, plus all benefits the employee would have received, had the employee been working a regular 40-hour work week. BPA shall have the right to conduct an audit to verify compliance with this section 4(i). If there is an interruption under this section 4(i), then the portion of Demand Entitlement interrupted shall be treated as if taken for purposes of section 7(b)(1)(A) and shall not be subject to the take-or-pay provisions in sections 4(a) and 4(b).

(j) **Modification of Whatcom's Obligations**

(1) Whatcom shall have no obligation to purchase any power from BPA under this Agreement except for such power that Alcoa is obligated to and does purchase from Whatcom under this Agreement. Whatcom shall have no obligation to make available to Alcoa any power under this Agreement except for such power that BPA is obligated to and does make available to Whatcom under this Agreement. Notwithstanding anything in this Agreement to the contrary, if the obligation of BPA to make available power to Whatcom or the obligation of Alcoa to purchase power from Whatcom are modified for any reason, including but not limited to curtailment, interruption or any change to the Demand Entitlement, then Whatcom's corresponding obligation to make power available to Alcoa and/or to purchase power from BPA shall be modified to the same extent.

(2) Whatcom's obligation to purchase power from BPA and Whatcom's obligation to make power available to Alcoa are contingent upon Alcoa performing its corresponding obligation's under this Agreement to purchase power from Whatcom and upon BPA performing its corresponding obligation to make power available to Whatcom. Whatcom's obligations under this Agreement to BPA and Alcoa shall

be excused and reduced to the extent of any nonperformance by Alcoa or BPA of their corresponding obligations under this Agreement to Whatcom.

5. BPA AND ALCOA OPTIONS

(a) **Monetary Benefits for the FY 07-09 Rate Period**
BPA has determined that, during the FY 07-09 Rate Period, in order to meet the cost caps described in the Administrator's ROD with certainty, it will monetize the physically delivered Surplus Firm Power sale obligation; provided, however, if Alcoa chooses an option specified in section 5(c) or 5(d) and/or 8(a)(4) below, then the physically delivered Surplus Firm Power sale obligation will be monetized for the entire Option Period. As such, BPA will make any MB Monthly Payments during the FY 07-09 Rate Period, the FY 10-11 Rate Period or the CY 2011 period, as applicable, subject to the provisions of section 5(c), 5(d), and 6 below.

(b) **BPA Option for the FY 10-11 Rate Period and the CY 2011 period**
PBL shall have the option to discontinue Monetary Benefits after the FY 07-09 Rate Period and to revert to a physically delivered Surplus Firm Power sale for the FY 10-11 Rate Period or for the CY 2011 period. This option is not applicable to the portion of MB Monthly Payments which Alcoa has chosen to lock in under section 5(c), 5(d), and/or 8(a)(4). If PBL chooses to exercise this option, then BPA shall provide written notice to Alcoa and Whatcom no later than October 1, 2008. In this event, the provisions of section 6 below shall not apply to that portion of Monetary Benefits that have reverted to a physically delivered Surplus Firm Power sale during the period this option is applicable, and this Agreement will operate in whole or in part as a physically delivered Surplus Firm Power sale, subject to the provisions of section 4 above, unless Alcoa elects to terminate this Agreement pursuant to section 16(b) below. In addition, in the event of a physical power sale, BPA will require Alcoa to provide performance assurances, consistent with BPA's then-current applicable credit policies.

Prior to exercising this option BPA shall conduct a public process providing an opportunity for customers to comment on the merits of exercising the option.

(c) **Alcoa Option for CY 2007-2009, CY 2007-2010 or CY 2007-2011**
Alcoa shall have a one time option to establish its MB Monthly Payments for CY 2007-2009, CY 2007-2010, or CY 2007-2011 pursuant to this section 5(c). If this option is selected by Alcoa, then the lower of the Forward Flat-Block Price Forecast, in effect on the date Alcoa provides written notice pursuant to this section 5(c), or the average purchase price paid for power to serve Alcoa's Total Plant Load during the Option Period shall establish the Forecast Market Price when calculating Alcoa's MB Monthly Payments as specified in section 6 below. The power purchase contracts entered into by Alcoa shall cover the full term of the Option Period and, except for UBA amounts subject to section 8(a)(4), shall be for all power included in the Monetary Benefit

calculation during the Option Period. If Alcoa chooses to exercise this option, then Alcoa shall provide written notice to BPA and Whatcom no later than September 30, 2006, specifying the CY 2007-2009, CY 2007-2010 or CY 2007-2011 period for which it has selected this option. In such event, the provisions of section 6(c)(6) shall not apply to Monetary Benefits subject to this option during the Option Period. Within 30 days of providing such notice Alcoa shall provide BPA access to contracts, invoices, or other documents reasonably necessary for BPA to verify the purchase price of power used to calculate Alcoa's MB Monthly Payments for this option.

(d) **Alcoa Option for CY 2010-2011 and CY 2011**
Provided Alcoa exercised either the CY 2007-2009 option or the CY 2007-2010 option specified in section 5(c) Alcoa shall also have a one time option to establish its MB Monthly Payments for the remainder of the Agreement. If Alcoa selects this option, then the lower of the Forward Flat-Block Price Forecast, in effect on the date Alcoa provides written notice pursuant to this section 5(d), or the average purchase price paid for power to serve Alcoa's Total Plant load during the Option Period shall establish the Forecast Market Price when calculating Alcoa's MB Monthly Payment specified in section 6 below. The power purchase contracts entered into by Alcoa shall cover the full term of the Option Period and, except for UBA amounts subject to section 8(a)(4), shall be for all power included in the Monetary Benefit calculation during the Option Period. If Alcoa chooses to exercise this option, then Alcoa shall provide written notice to BPA and Whatcom no later than September 30, 2007. In such event, the provisions of section 6(c)(6) shall not apply to Monetary Benefits subject to this option during the Option Period. Within 30 days of providing such notice, Alcoa shall provide BPA access to contracts, invoices, or other documents reasonably necessary for BPA to verify the purchase price of power used to calculate Alcoa's MB Monthly Payments for this option.

6. MONETARY BENEFIT PROVISIONS

This section 6 only applies when the physically delivered Surplus Firm Power sale is monetized. The provisions in section 4 shall not apply to Monetary Benefits.

(a) **Determination of Forecast Market Price and Equivalent PF for each CY or Option Period**
PBL shall determine the Forecast Market Price and Equivalent PF for each CY, using the procedures described in Exhibit F: provided, however, if Alcoa selects any option specified in section 5(c) or 5(d), then the Forward Market Price shall be determined as specified in the option(s) selected by Alcoa during the Option Period.

(b) **Determination of Monthly Plant Load**
No later than five (5) Business Days following the end of each month, PBL shall determine the Monthly Plant Load for each such month.

(c) **Determination of MB Monthly Payments**
Except as provided for in section 6(c)(5) below, the procedures described in Exhibit F and the following procedure, as described in sections 6(c)(1) through 6(c)(4), shall be used to determine the MB Monthly Payment for each month.

(1) Except as provided in section 6(c)(5), if the Monthly Plant Load is less than the Minimum Allocation during any month (Deficient Month), then the MB Monthly Payment for that month is $0.

(2) If the Monthly Plant Load is equal to or greater than the Maximum Allocation during any month, then the Monthly Plant Load shall be deemed equal to the Maximum Allocation for that month.

(3) The Maximum MB Monthly Payment for each month is determined by the following equation:

Maximum MB Monthly Payment = ((Maximum Allocation) x (number of hours in month)) x (lesser of $12/MWh or MB Rate);

provided, however, during the FY 07-09 Rate Period MB Monthly Payments for Option Benefits shall be determined by the following equation;

Maximum MB Monthly Payment = ((Maximum Allocation) x (number of hours in month)) x (lesser of $12/MWh x 0.92 or MB Rate).

(4) The MB Monthly Payment for each month shall be the lesser of the Maximum MB Monthly Payment determined pursuant to section 6(c)(3) above or the amount determined by the following equation:

MB Monthly Payment = ((Monthly Plant Load) x (number of hours in the month)) x (MB Rate)

(5) Alcoa may exercise the following one-time option. If Alcoa desires to exercise its one-time option pursuant to this section 6(c)(5), then Alcoa shall provide written notice to PBL and Whatcom that it will increase smelting load as of a date specified by Alcoa in such notice (Start Date). Then, for the remainder of the month that includes the Start Date and the following 2 months, the MB Monthly Payment shall be determined by the following equation:

MB Monthly Payment = (Total Plant Load) x MB Rate

Each MB Monthly Payment determined under this section 6(c)(5) shall not exceed the Maximum MB Monthly Payment.

(6) In addition to other limitations specified in the Agreement, Alcoa is only entitled to Monetary Benefits which when subtracted from the amount equal to its power costs to serve its Total Plant Load during the CY, does not reduce its power cost below the Equivalent PF multiplied by such total amount of power. If at any time during a Contract Year Alcoa knows it has procured power at a cost that will result in less than the full Monetary Benefits to reach the Equivalent PF, then Alcoa shall notify BPA of such cost and BPA shall reduce its payments accordingly for the remainder of the Contract Year.

This paragraph applies only for periods other than the Option Period, except with respect to acquired UBA not included in Option Benefits. Within 90 days following the end of each CY, BPA shall have the right to request: 1) Access to contracts, invoices or other documentation reasonably necessary for BPA to verify that purchases by Alcoa of power equal to the sum of Alcoa's Total Plant Loads for such CY and the cost of such purchases; and/or 2) A written certification from Alcoa's CFO of power purchases by Alcoa used to serve the sum of Alcoa's Total Plant Loads for such CY and the cost of such purchases. Alcoa shall provide BPA access to such contracts and documentation for such power purchases, subject to reasonable conditions to maintain the confidentiality of such information. If the difference between the cost of such purchases and their cost calculated as if they had been priced at the Equivalent PF is less than the sum of the Monetary Benefits that were paid to Alcoa for such CY, then Alcoa shall owe BPA such difference (Overpayment). BPA shall notify Alcoa of any such Overpayment and will reduce the total Monetary Benefits in the CY following the CY in which the Overpayment occurred by the amount of such Overpayment. If the Overpayment exceeds Monetary Benefits available during that following CY, then any unrecovered Overpayment will carryover to reduce Monetary Benefits in subsequent years until fully recovered.

If, upon termination of this Agreement, an Overpayment occurred for the CY prior to such termination, then, within 90 days following the end of such CY, BPA shall invoice Alcoa and Alcoa shall pay BPA such Overpayment within 20 days of receipt of such invoice.

(7) Notwithstanding anything to the contrary in this Agreement, in no case shall the annual Monetary Benefit total exceed the Monetary Benefit Limit specified in Exhibit E of this Agreement.

(d) **Examples**
Section 1 of Exhibit D contains several illustrative examples of the calculation of MB Monthly Payments, using a variety of assumptions.

7. DETERMINATION OF UNUSED BENEFIT AMOUNTS

The following procedures shall be used to determine UBA.

(a) **Determination of Unused Benefit Amounts During Periods When Surplus Firm Power Sale is Monetized**
This section 7(a) only applies when the physically delivered Surplus Firm Power sale is monetized.

(1) Beginning in October 2007, and following each month thereafter, PBL shall track the amount of Monetary Benefit that Alcoa has taken during each of the preceding 12 months.

(2) In order to retain its Maximum Allocation, Alcoa must, for at least one month during the preceding 12 months, have received the Maximum MB Monthly Payment. If this condition has not been satisfied, then the Maximum Allocation shall be reduced.

(3) Alcoa shall retain the highest monthly percentage of the available benefits that it accessed during the previous 12 months. As such, Alcoa's Maximum Allocation shall be reduced by the percentage of the available benefits, rounded to the nearest aMW, that were not accessed during the month that set the highest monthly percentage. The amount of aMW from this calculation becomes an Unused Benefit Amount or UBA.

(4) In the event of an UBA, PBL shall provide written notice to Alcoa and Whatcom that Alcoa's Maximum Allocation shall be reduced by the UBA. Such reductions shall become effective at 2400 hours on the last day of the month in the month the notice is provided (Date of Maximum Allocation Reduction). Alcoa understands and agrees that it will not have an option to re-acquire UBA that it has lost for one month following the Date of Maximum Allocation Reduction and that Other DSIs may acquire the UBA. BPA shall unilaterally revise Exhibit E, effective on the Date of Maximum Allocation Reduction, to reflect the reduced Maximum Allocation. BPA shall also provide notice of the availability of the UBA to the Other DSIs.

(b) **Determination of Unused Benefit Amounts During Periods When the Surplus Firm Power Sale Is Physically Delivered**
This section 7(b) only applies when the Surplus Firm Power sale is physically delivered.

(1) In order to assure its right to retain its Demand Entitlement, as specified in Exhibit E, Alcoa must, for at least one month during the preceding 12 months, have either (A) taken Surplus Firm Power equal to its Demand Entitlement during all hours of such month, or (B) taken the maximum Monetary Benefit available to it during such month. If this condition has not been satisfied, then the Demand Entitlement may be reduced.

(2) If the condition in section 7(b)(1) has not been satisfied, then BPA shall calculate the following for each of the previous 12 months:

(A) the percentage of the available Monetary Benefit received by Alcoa, and (B) the percentage of the Demand Entitlement taken by Alcoa. BPA may reduce the Demand Entitlement to the highest of such percentages multiplied by the Demand Entitlement, and rounded to the nearest MW. The MW amount of such reduction becomes an UBA.

(3) In the event of an UBA resulting from section 7(b)(2), PBL shall provide written notice to Alcoa and Whatcom that the Demand Entitlement may be reduced by the UBA. If all or a portion of such UBA is acquired by the Other DSIs pursuant to section 8(b) below, then the Demand Entitlement shall be reduced by the amount of UBA so acquired. Any such reduction shall become effective at 2400 hours on the last day of the month prior to the month that UBA has been acquired by the Other DSIs (Date of Demand Entitlement Reduction). BPA shall unilaterally revise Exhibit E, effective on the Date of Demand Entitlement Reduction, to reflect the reduced Demand Entitlement. If UBA made available under this section 7(b)(3) is not acquired by Alcoa or the Other DSIs within 6 months following the date such UBA became available, then BPA may, but shall not be obligated to, revise Exhibit E unilaterally to reduce the Demand Entitlement by the UBA not acquired.

(4) If an UBA results from a termination of this Agreement pursuant to section 16(b) below, then the entire Demand Entitlement becomes an UBA as of the effective date specified in section 16(b) below. BPA shall provide notice of the availability of any UBA that becomes available under this section 7(b)(4) to the Other DSIs pursuant to the notice provisions in section 7(b)(3) above. The Other DSIs may acquire this UBA pursuant to section 8(b) below.

(5) If Alcoa provides PBL and Whatcom written notice of curtailment under section 4(e)(1) and UBA will result during the term of such curtailment by operation of sections 7(b)(1) and 7(b)(2), then for purposes of sections 7(b)(2) and 7(b)(3), the UBA that would result during the term of the curtailment shall become UBA upon commencement of the curtailment.

(c) **Examples**
Section 2 of Exhibit D contains several illustrative examples of the determination of UBA, using a variety of assumptions.

8. OPTION TO ACQUIRE UNUSED BENEFIT AMOUNTS

The following procedures shall be used to acquire UBA.

(a) **Option to Acquire Unused Benefit Amounts During Periods When the Physically Delivered Surplus Firm Power Sale is Monetized**
This section 8(a) only applies when the physically delivered Surplus Firm Power sale is monetized.

(1) Unless Alcoa provides written notice to PBL and Whatcom that it has chosen not to acquire UBA, available UBA amounts will be added to Alcoa's Maximum Allocation, to the extent that doing so will increase the MB Monthly Payment it will receive for each month.

(2) During months when increases in Monthly Plant Load by Alcoa and Other DSIs exceed the amount of UBA available, UBA will be allocated pro rata to Alcoa and other DSIs, based on Maximum Allocation.

(3) BPA shall unilaterally revise Exhibit E to reflect the addition of acquired UBA in Alcoa's Maximum Allocation and Monetary Benefit Limit.

(4) If Alcoa has selected an Option Period under section 5(c) above, Monetary Benefits for the acquired UBA will not be included in calculations for Option Benefits and instead will be calculated separately under 6(c) above using the current Forecast Market Price as established under the provisions of Exhibit F of the Agreement unless and until Alcoa notifies BPA it will include the acquired UBA in the calculations to establish the MB Monthly Payments for the remainder of the Option Period. If this option is selected, then the purchase price used as the Forecast Market Price in the calculation of the Option Benefits shall be based on a megawatt hour weighted average of: i) the average purchase price previously used to calculate the Option Benefits, and ii) the average purchase price for acquired UBA, provided that the average purchase price for acquired UBA shall be limited by the Forecast Market Price in effect at the time Alcoa notifies BPA it will exercise this option.

If Alcoa chooses to exercise this option, then Alcoa shall provide written notice to BPA and Whatcom of the purchase price for the power purchased to serve the acquired UBA. For purposes of calculating MB Monthly Payments, the starting date of the purchase shall be the beginning of the month following the notice. Power purchases under this option must begin no later than 6 months following the effective date of the revision to Exhibit E for such acquired UBA. The provisions of section 6(c)(6) shall not apply to these UBA amounts during the Option Period. Instead, within 30 days of providing its power purchase notice, Alcoa shall provide BPA access to contracts, invoices, or other documents reasonably necessary for BPA to verify the purchase price of power used to calculate Alcoa's MB Monthly Payments for this option.

(5) UBA amounts that remain available and unused for 6 months following the Date of Reduction shall be zeroed out and will no longer be available to Alcoa or the Other DSIs during the term of this Agreement.

(b) **Option to Acquire Unused Benefit Amounts During Periods When the Surplus Firm Power is Physically Delivered**
This section 8(b) only applies when the Surplus Firm Power sale is physically delivered.

(1) Following receipt of a notice provided under section 7(b)(3) above, Alcoa shall provide written notice to PBL and Whatcom of the amount of UBA it wishes to purchase, if any.

(2) UBA amounts requested pursuant to section 8(b)(1) above will be added to the Demand Entitlement, effective on the first day of the month following receipt of the notice provided under section 8(b)(1) above.

(3) When requests for UBA by Alcoa and Other DSIs exceed the amount of UBA available, UBA will be allocated pro rata to Alcoa and other DSIs, based on Demand Entitlement.

(4) BPA shall unilaterally revise Exhibit E, effective on the date determined in 8(b)(2), to reflect an increase to the Demand Entitlement by the amount of acquired UBA.

(5) Any UBA acquired pursuant to this section 8(b) that remains unused after 6 months following the date specified in 8(b)(2) above will no longer be available to Alcoa or the Other DSIs. Amounts of Total Plant Load during such 6-month period that are less than the increased Demand Entitlement shall become an unused UBA. Such unused UBA shall be considered a Monthly Purchase Deficiency for each month of the remaining term of this Agreement, and Alcoa shall be subject to damages pursuant to section 4(e)(2) above.

(c) Any increased: (1) Maximum Allocation under section 8(a) above; or (2) Demand Entitlement under section 8(b) above shall not exceed 438 MW.

(d) Section 3 of Exhibit D contains several illustrative examples of the acquisition of UBA, using a variety of assumptions.

9. BILLING AND PAYMENT

(a) **Billing and Payment Provisions During Power Sale**
If, pursuant to section 5(b) above, BPA provides written notice that this Agreement will operate as a physically delivered Surplus Firm Power sale during the FY 10-11 Rate Period or the CY 11 period, then no later than March 1, 2009, the Parties shall amend this section 9(a) to include billing and payment provisions for: (1) the physically delivered Surplus Firm Power sale by PBL to Whatcom; and (2) the power sale by Whatcom to Alcoa.

(b) **Billing and Payment When Monetary Benefits Provided**

(1) **Escrow Account**
BPA and Whatcom shall establish an Escrow Account, in accordance with the laws governing Whatcom, for MB Monthly Payments and any interruption payments pursuant to section 4(i). BPA shall make payments into the Escrow Account, but only Whatcom shall have the ability to effect withdrawals from the Escrow Account for payment to Alcoa.

(2) **Payments into the Escrow Account**
Within five Business Days after the end of each month, BPA will review Alcoa's metered load measurements to determine if the Monthly Plant Load for the month is equal to or exceeds the Minimum Allocation.

Within eight Business Days following the end of the month, BPA shall transfer an amount equal to the MB Monthly Payment, and any interruption payments pursuant to section 4(i) above, into the Escrow Account.

(3) **Payments from the Escrow Account**
Within 12 business days following the end of the month, Whatcom shall effect the transfer of all BPA monthly payment amounts received into Escrow Account pursuant to this Agreement to Alcoa.

(4) **Escrow Account Safeguard**
Whatcom shall treat the Escrow Account in accordance with the terms of this Agreement and the agreement setting up the Escrow Account and not as property of Whatcom. Whatcom shall effect the release of such funds from the Escrow Account pursuant only to the escrow instructions consistent with this Agreement that BPA and Whatcom shall develop and provide to the escrow agent. Except to the extent Whatcom has failed to effect transfer of funds from the Escrow Account pursuant to the escrow instructions developed with BPA, Whatcom shall not be liable under any circumstances for the funds deposited by BPA into the Escrow Account, and BPA and Alcoa waive and release Whatcom from any and all claims, liability or damages that could arise from any loss, payment or lack of payment of such funds in the Escrow Account.

(c) **General Terms**

(1) Limitation on Whatcom's Payment Obligations
Notwithstanding anything in this Agreement to the contrary, Whatcom shall have no obligation under any circumstances to pay to BPA any amounts under this Agreement, FPS rate schedule and GRSPs except for such amounts that Whatcom has received from Alcoa under this Agreement, and Whatcom shall have no obligation under any circumstances to pay to Alcoa any amounts under this

Agreement except for such amounts that BPA paid into the Escrow Account under this Agreement and that are available for transfer to Alcoa.

(2) **Payment for Whatcom's Administrative Costs**
Notwithstanding anything in this Agreement to the contrary, to the extent that Whatcom incurs any expenses, fees, charges or costs of any kind not otherwise addressed in this Agreement, including but not limited to, attorneys fees, arising from Whatcom's development of and performance under this Agreement, Whatcom may bill Alcoa and Alcoa shall pay Whatcom for any such costs in addition to the cost of power delivered from Whatcom to Alcoa. Amounts that Alcoa pays Whatcom pursuant to this paragraph 9(c)(2) shall not be treated as amounts Whatcom has received from Alcoa for purposes of determining the limit on Whatcom's payment obligation to BPA under paragraph 9(c)(1) above.

10. NOTICES

Any notice required under this Agreement shall be in writing and shall be delivered: (a) in person; (b) by a nationally recognized delivery service; or (c) by United States Certified Mail. Notices are effective when received. Any Party may change its address for notices by giving notice of such change consistent with this section 10.

If to Alcoa:

Alcoa Inc.
6200 Malaga-ALCOA Highway
Malaga, WA 98828-9782
Attn: Jack A. Speer
Northwest Vice President,
Government and Energy Affairs
Phone: 509-663-9331
FAX: 509-663-9200
E-Mail: Jack.speer@alcoa.com

If to PBL:

Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621
Attn: Mark E. Miller
Account Executive
Phone: 503-230-4003
FAX: 503-230-3681
E-Mail: memiller@bpa.gov

If to Whatcom:

Whatcom County PUD No. 1
1705 Trigg Road
Ferndale, Washington 98248
Attn: Brian Walters
Power Resources and Contract Manager
Phone: 360-384-4288, ext. 25
FAX: 360-384-4849
E-Mail: brianwalters@pudwhatcom.org

11. UNCONTROLLABLE FORCES

(a) **Uncontrollable Forces Provisions During Surplus Firm Power Sale**
If, during the FY 10-11 Rate Period, this Agreement operates as a physical Surplus Firm Power Sale, then the following provisions shall apply; *provided however,* that UBA determinations pursuant to section 7 and acquisitions of UBA pursuant to section 8 shall not be subject to Uncontrollable Forces under this section 11(a).

PBL shall not be in breach of its obligation to provide Surplus Firm Power to Whatcom and Whatcom shall not be in breach of its obligation to purchase Surplus Firm Power to the extent the failure to fulfill that obligation is due to an Uncontrollable Force. Similarly, Whatcom shall not be in breach of its obligation to provide Surplus Firm Power to Alcoa and Alcoa shall not be in breach of its obligation to purchase Surplus Firm Power to the extent the failure to fulfill that obligation is due to an Uncontrollable Force. "Uncontrollable Force" means an event beyond the reasonable control of, and without the fault or negligence of, the Party claiming the Uncontrollable

Force that prevents that Party from performing its obligations under this Agreement and which, by exercise of that Party's reasonable diligence and foresight, such Party could not be expected to avoid and was unable to avoid. Uncontrollable Forces include, but are not limited to:

(1) any unplanned curtailment or interruption for any reason of firm transmission used to deliver Surplus Firm Power to Alcoa's facilities, including but not limited to unplanned maintenance outages;

(2) any unplanned curtailment or interruption, failure or imminent failure of Alcoa's production or transmission facilities, including but not limited to unplanned maintenance outages;

(3) any planned transmission or distribution outage that affects either Alcoa or PBL which was provided by a third-party transmission or distribution owner, or by a transmission provider, including TBL, that is functionally separated from the generation provider in conformance with Federal Energy Regulatory Commission (FERC) Orders 888 and 889 or its successors;

(4) strikes or work stoppage, including the threat of imminent strikes or work stoppage; *provided, however*, that nothing contained in this provision shall be construed to require any Party to settle any strike or labor dispute in which it may be involved.

(5) floods, earthquakes, or other natural disasters; and

(6) orders or injunctions issued by any court having competent subject matter jurisdiction, or any order of an administrative officer which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court of competent subject matter jurisdiction.

Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic hardship of any Party shall not constitute an Uncontrollable Force. The Party claiming the Uncontrollable Force shall notify the other Parties as soon as practicable of that Party's inability to meet its obligations under this Agreement due to an Uncontrollable Force. The Party claiming the Uncontrollable Force shall notify any control area involved in the scheduling of a transaction which may be curtailed due to an Uncontrollable Force.

All Parties shall be excused from their respective obligations, other than from payment obligations incurred prior to the Uncontrollable Force, without liability to the other, for the duration of the Uncontrollable Force and the period reasonably required for the Party claiming the Uncontrollable Force, using due diligence, to restore its operations to conditions existing prior to the occurrence of the Uncontrollable Force.

(b) **Uncontrollable Forces Provisions During Periods When Monetary Benefit is Provided**
During periods when the Surplus Firm Power sale is monetized, Alcoa understands and agrees that there are no events that will be considered Uncontrollable Forces under this Agreement.

12. GOVERNING LAW AND DISPUTE RESOLUTION

(a) This Agreement shall be interpreted consistent with and governed by Federal law. Disputes arising out of this Agreement that are not otherwise subject to the exclusive jurisdiction of the United States Court of Appeals for the Ninth Circuit are subject to the Contract Disputes Act, 41 USC 601, et seq.

(b) If a dispute arises under any provision of this Agreement, the Parties shall, within 14 business days following the initiation of a dispute, make a good faith effort to negotiate a resolution of such dispute before initiating the mediation provisions in section 12(c) below.

(c) If the Parties are unable to agree following negotiation pursuant to section 12(b) above, then either Party may request, in writing, to mediate the dispute. The Parties shall seek to reach agreement upon a mediator. In the event that they are unable to agree, then a mediator shall be selected by U.S. Arbitration and Mediation of Oregon. The Parties shall have 30 days from the date a Party initiated mediation to reach agreement before initiating litigation. BPA and Alcoa shall each pay one half of the expenses of any mediation between or among the Parties.

(d) During a contract dispute or contract issue between or among Parties arising out of this Agreement, the Parties shall continue performance under this Agreement pending resolution of the dispute, unless to do so would be impossible or impractical. The Parties reserve the right to seek judicial resolution of any dispute arising out of this Agreement.

13. STATUTORY PROVISIONS

(a) **Priority of Pacific Northwest Customers**
The provisions of sections 9(c) and (d) of the Northwest Power Act and the provisions of P.L. 88-552 as amended by the Northwest Power Act are incorporated into this Agreement by reference. Whatcom, together with other customers in the Region, shall have priority to BPA power, consistent with such provisions.

(b) **Limitation on Resale**
Whatcom shall not resell Surplus Firm Power, as defined in this Agreement, to any entity except Alcoa.

(c) **BPA Appropriations Refinancing Act**
The BPA Refinancing Section of the Omnibus Consolidated Rescissions and Appropriations Act of 1996 (The BPA Refinancing Act), P.L. No. 104-134, 110

Stat. 1321, 1350, is incorporated by reference and is a material term of this Agreement.

14. STANDARD PROVISIONS

(a) **Amendments**
No oral or written amendment, rescission, waiver, modification, or other change of this Agreement shall be of any force or effect unless set forth in a written instrument signed by authorized representatives of each Party.

(b) **Assignment**
Alcoa may assign this Agreement upon 90 days prior written notice, but only to a successor-in-interest that has acquired ownership, through purchase or merger, of Alcoa's facilities that are served, in whole or in part, with power or Monetary Benefits provided under this Agreement, and then only if such assignee expressly agrees in writing to be bound by the terms of this Agreement. In the event of such assignment, BPA will apply its then current credit policies to determine whether it will require security or assurances from the assignee to secure performance of assignee's obligations under this Agreement. Monetary Benefits under this Agreement are not transferable for use at other aluminum smelters. Such Monetary Benefits shall only be available for eligible production facilities referred to in Exhibit B of this Agreement, subject to any limitations specifically established in Exhibit B.

(c) **Information Exchange and Confidentiality**
The Parties shall provide each other with any information that is reasonably required, and requested by any Party in writing, to operate under and administer this Agreement, including load forecasts for planning purposes, information needed to resolve billing disputes, scheduling, and metering information reasonably necessary to prepare power bills that is not otherwise available to the requesting Party. Such information shall be provided in a timely manner. Information may be exchanged by any means agreed to by the Parties. If such information is subject to a privilege of confidentiality, a confidentiality agreement or statutory restriction under state or Federal law on its disclosure by a Party to this Agreement, then that Party shall endeavor to obtain whatever consents, releases, or agreements are necessary from the person holding the privilege to provide such information while asserting the confidentiality over the information. Information provided to BPA which is subject to a privilege of confidentiality or nondisclosure shall be clearly marked as such and BPA shall not disclose such information without obtaining the consent of the person or Party asserting the privilege, consistent with BPA's obligation under the Freedom of Information Act. BPA may use such information as necessary to provide service or timely bill for service under this Agreement. BPA shall only disclose information received under this provision to BPA employees who need the information for purposes of this Agreement.

(d) **Entire Agreement**
This Agreement, including all provisions, exhibits incorporated as part of this Agreement, and documents incorporated by reference, constitutes the entire agreement among the Parties. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement.

(e) **Exhibits**
The exhibits listed in the table of contents are incorporated into this Agreement by reference. The exhibits may only be revised upon mutual agreement among the Parties unless otherwise specified in the exhibits. The body of this Agreement shall prevail over the exhibits to this Agreement in the event of a conflict.

(f) **No Third-Party Beneficiaries**
This Agreement is made and entered into for the sole protection and legal benefit of the Parties, and no other person shall be a direct or indirect legal beneficiary of, or have any direct or indirect cause of action or claim in connection with this Agreement.

(g) **Waivers**
Any waiver at any time by any Party to this Agreement of its rights with respect to any default or any other matter arising in connection with this Agreement shall not be considered a waiver with respect to any subsequent default or matter.

(h) **BPA Policies**
Any reference in this Agreement to BPA policies, including without limitation BPA's New Large Single Load Policy and the 5(b)/9(c) Policy, and any revisions thereto, does not constitute agreement by Alcoa or Whatcom to such policy, nor shall it be construed to be a waiver of the right of Alcoa or Whatcom to seek judicial review of any such policy.

(i) **Severability**
If any term of this Agreement is found to be invalid by a court of competent jurisdiction then such term shall remain in force to the maximum extent permitted by law. All other terms shall remain in force unless that term is determined not to be severable from all other provisions of this Agreement by such court.

(j) **Hold Harmless**
BPA and Alcoa assume all liability for injury or damage to persons or property arising from the act or negligence of its own employees, agents, members of governing bodies, or contractors. BPA and Alcoa shall indemnify and hold the other Parties harmless from any liability arising from such act or negligence.

15. LIMITATION OF LIABILITY OF WHATCOM AND HOLD HARMLESS

BPA and Alcoa agree to and hereby do waive any suit, claim, demand or cause of action of any kind in law and equity which they may have or may assert against Whatcom arising out of this Agreement, except to enforce Whatcom's obligations pursuant to this Agreement (i) to effect transfer of Escrow Account funds pursuant to section 9(b) of this Agreement, and (ii) to pay such amounts received from Alcoa to BPA in the amount of payments received by Whatcom from Alcoa pursuant to section 9(a) of this Agreement as may be amended pursuant to section 9(a) of this Agreement.

In no event or any circumstance shall Whatcom be liable for special punitive, indirect, incidental or consequential losses or damages of any kind whatsoever (including but not limited to lost profits), even if Whatcom has been advised of the likelihood of such loss or damage and regardless of the form of action.

Furthermore, BPA and Alcoa agree to share equally any payment necessary to indemnify, hold harmless and reimburse Whatcom for damages and/or any reasonable costs, other than Whatcom's implementation and administrative costs billable to Alcoa under section 9 of this Agreement, including, but not limited to, reasonable attorney fees, incurred by Whatcom as a direct or indirect result of its participation in this Agreement.

BPA's and Alcoa's agreement to indemnify and hold harmless Whatcom pursuant to this section 15 shall survive the termination of this Agreement until extinguished by any applicable statue of limitations.

16. TERMINATION

(a) BPA may terminate this Agreement on 30 days written notice to the other Parties in the event the Ninth Circuit Court of Appeals or other court of competent jurisdiction issues a final, unappealable order preventing or prohibiting BPA from recovering under the Slice Agreements or its Slice rate schedules that portion of BPA's cost of service associated with this Agreement allocated by BPA to such Slice Agreements or Slice rate schedules. BPA shall diligently litigate any action challenging its ability to assess such costs. Neither Alcoa nor Whatcom shall be entitled to any damages for such termination and hereby expressly waives any right to seek such damages.

(b) If, pursuant to section 5(b) above, BPA provides written notice to convert the payment of Monetary Benefit to a physical Surplus Firm Power Sale during the CY 2010-2011 period or the CY 2011period, then Alcoa may terminate this Agreement by providing written notice to Whatcom and BPA no later than November 1, 2008. The effective date of any such termination shall be 2400 hours on the September 30 immediately preceding the effective date of such conversion. In this event, the Demand Entitlement becomes an UBA as of the effective date specified in this section 16(b), and shall be offered to Other DSIs pursuant to section 7(b)(4) above.

(c) In the event the Ninth Circuit Court of Appeals or other court of competent jurisdiction issues a final order that declares or renders this Agreement void or otherwise unenforceable, no Party shall be entitled to any damages or restitution of any nature, in law or equity, from any other Party, and each Party hereby expressly waives any right to seek such damages.

(d) Whatcom may terminate its obligations under this Agreement upon 30 days written notice to the other Parties if there is an Event of Default by Alcoa. An Event of Default shall mean the failure of Alcoa to pay when due the reimbursements owed by Alcoa to Whatcom under sections 9(c)(2), 12(c), 14(j) and/or 15 if payment is not remedied within 30 Business Days after written notice. In the event of such termination by Whatcom, BPA and Alcoa will establish a mutually agreeable alternative means to effectuate the payments and the acquisition of BPA power by Alcoa provided for in this Agreement.

17. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom they sign.

ALCOA INC.

By **/S/ ALAN CRANSBERG**

Name **Alan Cransberg**
(Print/Type)

Title **President, Global Mfg.**

Date **June 19, 2006**

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By **/S/ MARK E. MILLER**
Account Executive

Name Mark E. Miller
(Print/Type)

Date **June 9, 2006**

PUBLIC UTILITY DISTRICT NO. 1 OF
WHATCOM COUNTY, WASHINGTON

By **/S/ STEPHAN JILK**

Name **Stephan Jilk**
(Print/Type)

Title **General Manager**

Date **June 13, 2006**

Exhibit A
SURPLUS FIRM POWER RATE

If BPA chooses to exercise its option, pursuant to section 5(b) of the body of this Agreement, to sell physically delivered Surplus Firm Power under this Agreement during the FY 10-11 Rate Period, then BPA shall unilaterally revise this Exhibit A, effective on October 1, 2009, to include the specific rates and charges that will apply to the physically delivered Surplus Firm Power sale. The cost to BPA to provide such physically delivered Surplus Firm Power will not exceed the cost caps as described in the Administrator's ROD.

Exhibit B
ADDITIONAL PRODUCTS, SERVICES, AND SPECIAL PROVISIONS

1. DESCRIPTION OF ALCOA's PRODUCTION FACILITIES, STATION SERVICE REQUIREMENTS, AND METERING EQUIPMENT

Production Facilities: are Alcoa's aluminum smelting facilities served from the Government's Intalco Substation, where the 13.8 kilovolt (kV) facilities of BPA and Alcoa are connected. If Alcoa requests a Companion Contract pursuant to section 2 of this Exhibit B for its Wenatchee smelter, located at Wenatchee, Washington, the portion of the Wenatchee smelter load that has been traditionally served with purchases from Chelan PUD will be excluded from Alcoa's Total Plant Load and the cost of these purchases will be excluded from the calculation of Monetary Benefits under this Agreement.

Metering Equipment: used to measure energy usage of Alcoa's facilities at the Government's Intalco Substation in the 13.8 kV circuits over which such electric power and energy flows.

Alcoa agrees to allow PBL access to all hourly load measurements of its Production Facilities necessary to administer this Agreement.

2. SECOND CONTRACT RIGHT

At any time during the term of this contract Alcoa may request a contract to serve the Wenatchee smelter. BPA shall offer Alcoa and the Utility that shall serve the Wenatchee smelter a contract (Companion Contract) with the same terms and conditions as this contract, but with the eligible production facilities at the Wenatchee smelter incorporated and with the following revisions, which revisions shall also simultaneously be incorporated into this contract:

Section 6(c)(1) of this Agreement shall be replaced with the following:

> "Alcoa shall have the right to transfer Maximum Allocation amounts among this Agreement and a Companion Contract entered into between BPA, Alcoa, and another utility as specified in Exhibit E of this Agreement. If the total Monthly Plant Load plus the total Monthly Plant Load of the Companion Contract is less than ¼ of the Total Maximum Allocation during any month (Deficient Month), then the MB Monthly Payment for that month is $0."

Exhibit E shall be replaced with the following:

"Exhibit E
MAXIMUM ALLOCATION, MINIMUM ALLOCATION, AND DEMAND ENTITLEMENT

1. **MAXIMUM AND MINIMUM ALLOCATIONS**
During periods when Monetary Benefit payments are provided pursuant to section 6 of the body of this Agreement, the Maximum Allocation, Minimum Allocation, and Monetary Benefit Limit amounts are as follows:

Maximum Allocation:	320 aMW
Minimum Allocation:	80 aMW
Monetary Benefit Limit:	$33,638,400/CY (Leap Year $92,160 greater.)

Total Maximum Allocation shall be equal to the summation of Maximum Allocation amounts specified in this Exhibit E and in the Companion Contract:

Total Maximum Allocation: 320 aMW

2. **DEMAND ENTITLEMENT**
During periods when this Agreement operates as a physical Surplus Firm Power sale pursuant to section 4 of the body of this Agreement, the Demand Entitlement shall be as follows:

Demand Entitlement: 320 MW

Total Demand Entitlement shall equal the summation of Demand Entitlement amounts specified in this Exhibit B and in the Companion Contract:

Total Demand Entitlement: 320 aMW

3. **MAXIMUM ALLOCATION AND DEMAND ENTITLEMENT TRANSFERS**
Alcoa may transfer amounts of Maximum Allocation and amounts of Demand Entitlement among this Agreement and a Companion Contract as specified in this Exhibit E. The total of Alcoa's Maximum Allocation amounts and Demand Entitlement amounts specified in these contracts may not exceed Alcoa's Total Maximum Allocation or Total Demand Entitlement. Alcoa shall provide both BPA and Whatcom at least 7 days advance written notice of the effective date of such transfers. The effective date must be the first day of a month. BPA shall revise this Exhibit E to reflect such changes to Maximum Allocation, Minimum Allocation, and/or Demand Entitlement.

4. **REVISIONS**
BPA shall unilaterally revise this Exhibit E to reflect changes to Maximum Allocation, Total Maximum Allocation, Minimum Allocation, and/or Demand Entitlement and Total Demand Entitlement under this Agreement, except as provided for in section 3 of this Exhibit E."

3. REVISIONS

This Exhibit B shall be revised upon mutual agreement of the Parties to reflect any new products, services, and special provisions that may be added during the term of this Agreement.

Exhibit C
BPA POWER BUSINESS LINE SCHEDULING PROVISIONS

1. PURPOSE OF THIS EXHIBIT

Unless otherwise specified in this Exhibit C, all transactions shall be scheduled in accordance with the Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Council (NERC). The purpose of this exhibit is to identify power scheduling requirements and coordination procedures necessary for the delivery of electric power products bought or sold under this Agreement. All provisions apply equally to all BPAP Counter Parties (as defined in section 2 below) and their authorized scheduling agents. Transmission scheduling arrangements are provided under separate agreements/provisions with the designated transmission provider.

2. DEFINITIONS

(a) **After the Fact**: The process of reconciling all transactions, Schedules, and accounts after they have occurred.

(b) **APOD**: Alternate Point Of Delivery. Any point other than the POD specified in a Confirmation Agreement or other contract to which this Exhibit C applies.

(c) **BPAP**: Bonneville Power Administration Power Business Line.

(d) **BPAP Counter Party**: A PSE (Purchasing Selling Entity, as defined by NERC) that has contracted to purchase from BPAP or sell to BPAP electric power products.

(e) **COB**: California-Oregon Border or COI (California-Oregon Intertie). Consists of the Pacific AC Intertie (PACI or Malin) and 3rd AC Intertie (3A or Captain Jack) transmission lines to California. N to S indicates that the energy is flowing on the transmission path North to South. S to N indicates energy is flowing on the transmission path South to North.

(f) **NOB**: Nevada-Oregon Border. Consists of the Pacific DC Intertie (PDCI or Celilo) transmission line to California. N to S indicates that the energy is flowing on the transmission path North to South. S to N indicates energy is flowing on the transmission path South to North.

(g) **POD**: Point of Delivery, as defined by NERC.

(h) **Preschedule Day**: Preschedule Day is in accordance with WECC practice and variations are identified in the WECC calendar to allow for Holidays, WECC meetings, etc.

(i) **Prescheduling**: The process (verbally and in writing) of establishing and balancing (checking out) schedules on the Preschedule Day.

(j) **Real-Time Scheduling**: Any new or modified Transaction that occurs after prescheduling is completed.

(k) **Schedule**: The planned Transaction approved and accepted by all counterparties and Control Areas involved in the Transaction.

3. COORDINATION: GENERAL, CONTROL AREA, PRESCHEDULE, REAL-TIME, AND AFTER-THE-FACT REQUIREMENTS

(a) **General Requirements**

(1) BPAP shall have the right to revise and replace this Exhibit C: (1) in the event that scheduling procedures are changed due to agreement among scheduling parties in the WECC; (2) to comply with rules or orders issued by the Federal Energy Regulatory Commission (FERC) or NERC, or (3) to implement changes reasonably necessary for BPAP to administer its power scheduling function in a more efficient manner.

(2) BPAP and each BPAP Counter Party must have necessary staff available during both parties' Prescheduling, Real-Time Scheduling, and After the Fact check out processes, including the completion of the NERC Etag.

(3) All transactions shall be stated in the Pacific Prevailing Time (PT), beginning with the 0100 hour ending.

(4) BPAP and each BPAP Counter Party shall notify each other of changes to telephone or fax numbers of key personnel (for Prescheduling, Real-Time Scheduling, After the Fact, or scheduling agents, etc.).

(b) **Prescheduling Requirements**

(1) **Information Required For Any Preschedule**

(A) When the NERC Tag is prepared, the BPAP Counter Party purchasing from BPAP shall use commercially reasonable efforts to ensure the BPAP Confirmation Agreement contract number is included within the generation/load segment, in the XML "Contract Number" element of the Etag.

(B) Transactions to or from COB must identify the use of either Malin or Captain Jack.

(2) **Preschedule Coordination**
Final hourly Schedules must be submitted by each BPAP Counter Party to BPAP for the next day(s) transactions by 1100 PT of each Preschedule Day, unless otherwise agreed. After 1100 PT Preschedules can be accepted if mutually agreed to by BPAP and the BPAP Counter Party, and the Preschedules are accepted by the transmission provider(s).

(c) **Real-Time Scheduling Requirements**

(1) BPAP Counter Parties may not make real-time changes to the schedules unless such changes are allowed under specific Confirmation Agreements or other contracts to which this Exhibit C applies, and by mutual agreement.

(2) If real-time changes to the schedule become necessary and are allowable as described in section 3(c)(1) above, the requesting BPAP Counter Party must submit requests for such changes no later than specified in the contract or BPAP Confirmation Agreement. Emergency schedule changes (including mid-hour changes) will be handled in accordance with WECC procedures.

(3) Multi-hour changes to the schedule shall specify an "hour beginning" and an "hour ending" and shall not be stated as "until further notice."

(d) **After the Fact Reconciliation Requirements**
Each BPAP Counter Party agrees to reconcile all transactions, Schedules, and accounts following the end of each month (within the first 10 calendar days of the next month).

Exhibit D
EXAMPLES

I. EXAMPLES OF THE CALCULATION OF MONETARY BENEFIT PAYMENTS

Following are examples of the calculation of Monetary Benefit payments pursuant to section 6 of the body of this Agreement.

Example No. 1: Calculation of MB Rate, Maximum MB Monthly Payment, and MB Monthly Payment.

Demand Entitlement	250	aMW
Hours in the Month Equals	744	

Difference Between Forecast Market Price and Equvalent PF	MB Rate	Maximum MB Payment	Minimum Load (aMW) to Receive Maximum MB Monthly Payment
$26.00	$24.00	$2,232,000	125.0000
$25.00	$24.00	$2,232,000	125.0000
$24.00	$24.00	$2,232,000	125.0000
$23.00	$24.00	$2,232,000	130.4348
$22.00	$24.00	$2,232,000	136.3636
$21.00	$24.00	$2,232,000	142.8571
$20.00	$24.00	$2,232,000	150.0000
$19.00	$19.00	$2,232,000	157.8947
$18.00	$18.00	$2,232,000	166.6667
$17.00	$17.00	$2,232,000	176.4706
$16.00	$16.00	$2,232,000	187.5000
$15.00	$15.00	$2,232,000	200.0000
$14.00	$14.00	$2,232,000	214.2857
$13.00	$13.00	$2,232,000	230.7692
$12.00	$12.00	$2,232,000	250.0000
$11.00	$11.00	$2,046,000	250.0000
$10.00	$10.00	$1,860,000	250.0000
$9.00	$9.00	$1,674,000	250.0000
$8.00	$8.00	$1,488,000	250.0000
$7.00	$7.00	$1,302,000	250.0000
$6.00	$6.00	$1,116,000	250.0000
$5.00	$5.00	$930,000	250.0000
$4.00	$4.00	$744,000	250.0000
$3.00	$3.00	$558,000	250.0000
$2.00	$2.00	$372,000	250.0000
$1.00	$1.00	$186,000	250.0000
$0.00	$0.00	$0	0.0000

Example No. 2: Difference between Forecast Market Price and Equivalent PF exceeds $24/MWh and the DSI's operation varies from less than its Minimum Allocation to its Maximum Allocation.

Forecast of Maximum MB Monthly Payment for CY

	October	November	December	January	February	March
Hours in the Month	745	720	744	744	672	744
Market Forecast (FBPF)	$ 60.00	$ 60.00	$ 60.00	$ 60.00	$ 60.00	$ 60.00
Equivalent PF	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00
Maximum MB Rate	$ 24.00	$ 24.00	$ 24.00	$ 24.00	$ 24.00	$ 24.00
Demand Entitlement - MW	250	250	250	250	250	250
Maximum MB Monthly Pmt	$2,235,000	$2,160,000	$2,232,000	$2,232,000	$2,016,000	$2,232,000

	April	May	June	July	August	September
Hours in the Month	719	744	720	744	744	720
Market Forecast (FBPF)	$ 60.00	$ 60.00	$ 60.00	$ 60.00	$ 60.00	$ 60.00
Equivalent PF	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00
Maximum MB Rate	$ 24.00	$ 24.00	$ 24.00	$ 24.00	$ 24.00	$ 24.00
Demand Entitlement - MW	250	250	250	250	250	250
Maximum MB Monthly Pmt	$2,157,000	$2,232,000	$2,160,000	$2,232,000	$2,232,000	$2,160,000

Equivalent PF subject to same adjustments established for the PF rate.

CY MB Monthly Payments, Demand Entitlement Equals 250 MW

	Minimum Load Requirement	Maximum MB Monthly Payment	Actual Monthly Load (MWh)	Monthly Plant Load (aMW)	Meets Minimum Load Requirement?	MB Monthly Payment
October	46,563	$ 2,235,000	63,000	84.6	**Yes**	$ 1,512,000
November	45,000	$ 2,160,000	61,000	84.7	**Yes**	$ 1,464,000
December	46,500	$ 2,232,000	60,000	80.6	**Yes**	$ 1,440,000
January	46,500	$ 2,232,000	44,500	59.8	**No**	$ -
February	42,000	$ 2,016,000	40,500	60.3	**No**	$ -
March	46,500	$ 2,232,000	45,000	60.5	**No**	$ -
April	44,938	$ 2,157,000	44,000	61.2	**No**	$ -
May	46,500	$ 2,232,000	46,000	61.8	**No**	$ -
June	45,000	$ 2,160,000	60,000	83.3	**Yes**	$ 1,440,000
July	46,500	$ 2,232,000	80,000	107.5	**Yes**	$ 1,920,000
August	46,500	$ 2,232,000	90,000	121.0	**Yes**	$ 2,160,000
September	45,000	$ 2,160,000	97,500	135.4	**Yes**	$ 2,160,000
		26,280,000	731,500			$ 12,096,000

In this example the DSI is entitled to the Maximum MB Monthly Payment each month that the actual monthly load equals or exceeds the Minimum Allocation. January through May monthly loads were less than the Minimum Allocation Requirement, and the MB Monthly Payments equal zero.

Example No. 3: Difference between Forecast Market Price and Equivalent PF equals $18/MWh and the DSI's operation varies from less than its Minimum Allocation to its Maximum Allocation

Forecast of Maximum MB Monthly Payment for CY

	October	November	December	January	February	March
Hours in the Month	745	720	744	744	672	744
Market Forecast (FBPF)	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00
Equivalent PF	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00
Maximum MB Rate	$ 18.00	$ 18.00	$ 18.00	$ 18.00	$ 18.00	$ 18.00
Demand Entitlement - MW	250	250	250	250	250	250
Maximum MB Monthly Pmt	$ 2,235,000	$ 2,160,000	$ 2,232,000	$ 2,232,000	$ 2,016,000	$ 2,232,000

	April	May	June	July	August	September
Hours in the Month	719	744	720	744	744	720
Market Forecast (FBPF)	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00
Equivalent PF	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00
Maximum MB Rate	$ 18.00	$ 18.00	$ 18.00	$ 18.00	$ 18.00	$ 18.00
Demand Entitlement - MW	250	250	250	250	250	250
Maximum MB Monthly Pmt	$ 2,157,000	$ 2,232,000	$ 2,160,000	$ 2,232,000	$ 2,232,000	$ 2,160,000

Equivalent PF subject to same adjustments established for the PF rate.

CY MB Monthly Payments, Demand Entitlement Equals 250 MW

	Minimum Load Requirement	**Maximum MB Payment**	**Monthly Plant Load (MWh)**	**Actual Monthly Load (aMW)**	**Meets Minimum Load Requirement?**	**MB Monthly Payment**
October	46,563	$ 2,235,000	63,000	84.6	**Yes**	$ 1,134,000
November	45,000	$ 2,160,000	61,000	84.7	**Yes**	$ 1,098,000
December	46,500	$ 2,232,000	60,000	80.6	**Yes**	$ 1,080,000
January	46,500	$ 2,232,000	44,500	59.8	**No**	$ -
February	42,000	$ 2,016,000	40,500	60.3	**No**	$ -
March	46,500	$ 2,232,000	45,000	60.5	**No**	$ -
April	44,938	$ 2,157,000	44,000	61.2	**No**	$ -
May	46,500	$ 2,232,000	46,000	61.8	**No**	$ -
June	45,000	$ 2,160,000	60,000	83.3	**Yes**	$ 1,080,000
July	46,500	$ 2,232,000	80,000	107.5	**Yes**	$ 1,440,000
August	46,500	$ 2,232,000	90,000	121.0	**Yes**	$ 1,620,000
September	45,000	$ 2,160,000	97,500	135.4	**Yes**	$ 1,755,000
		26,280,000	731,500			$ 9,207,000

In this example the DSI is entitled to the Maximum MB Monthly Payment only September. January thru May MB Monthly Payments equal zero because the DSI failed to meet the Minimum Allocation requirement. For the remaining months an MB Monthly Payment equal to the actual monthly load multiplied by the MB Rate ($18.00/MWh) was paid.

Example No. 4: Difference between Forecast Market Price and Equivalent PF equals $8/MWh and the DSI's operation varies from less than its Minimum Allocation to its Maximum Allocation.

Forecast of Maximum MB Monthly Payment for CY

	October	November	December	January	February	March
Hours in the Month	745	720	744	744	672	744
Market Forecast (FBPF)	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00
Equivalent PF	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00
Maximum MB Rate	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00
Demand Entitlement - MW	250	250	250	250	250	250
Maximum MB Monthly Pmt	$ 1,490,000	$ 1,440,000	$ 1,488,000	$ 1,488,000	$ 1,344,000	$ 1,488,000

	April	May	June	July	August	September
Hours in the Month	719	744	720	744	744	720
Market Forecast (FBPF)	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00
Equivalent PF	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00
Maximum MB Rate	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00
Demand Entitlement - MW	250	250	250	250	250	250
Maximum MB Monthly Pmt	$ 1,438,000	$ 1,488,000	$ 1,440,000	$ 1,488,000	$ 1,488,000	$ 1,440,000

Equivalent PF subject to same adjustments established for the PF rate.

CY MB Monthly Payments, Demand Entitlement Equals 250 MW

	Minimum Load Requirement Minus	Maximum MB Monthly Payment	Actual Monthly Load (MWh)	Monthly Plant Load (aMW)	Meets Minimum Load Requirement?	MB Monthly Payment
October	46,563	$ 1,490,000	63,000	84.6	**Yes**	$ 504,000
November	45,000	$ 1,440,000	61,000	84.7	**Yes**	$ 488,000
December	46,500	$ 1,488,000	60,000	80.6	**Yes**	$ 480,000
January	46,500	$ 1,488,000	44,500	59.8	**No**	$ -
February	42,000	$ 1,344,000	40,500	60.3	**No**	$ -
March	46,500	$ 1,488,000	45,000	60.5	**No**	$ -
April	44,938	$ 1,438,000	44,000	61.2	**No**	$ -
May	46,500	$ 1,488,000	46,000	61.8	**No**	$ -
June	45,000	$ 1,440,000	60,000	83.3	**Yes**	$ 480,000
July	46,500	$ 1,488,000	80,000	107.5	**Yes**	$ 640,000
August	46,500	$ 1,488,000	90,000	121.0	**Yes**	$ 720,000
September	45,000	$ 1,440,000	97,500	135.4	**Yes**	$ 780,000
		17,520,000	731,500			$ 4,092,000

In this example, January through May the MB Monthly Payment equals zero because the DSI failed to meet the Minimum Allocation requirement. In the remaining months the MB Monthly Payment equals actual monthly load multiplied by the MB Rate ($8.00/MWh).

Example No. 5: Equivalent PF is greater than the Forecast Market Price and the DSI's operation varies from less than its Minimum Allocation to its Maximum Allocation

Forecast of Maximum MB Monthly Payment for CY

	October	November	December	January	February	March
Hours in the Month	745	720	744	744	672	744
Market Forecast (FBPF)	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00
Equivalent PF	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00
Maximum MB Rate	$ -	$ -	$ -	$ -	$ -	$ -
Demand Entitlement - MW	250	250	250	250	250	250
Maximum MB Monthly Pmt	$ -	$ -	$ -	$ -	$ -	$ -

	April	May	June	July	August	September
Hours in the Month	719	744	720	744	744	720
Market Forecast (FBPF)	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00
Equivalent PF	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00
Maximum MB Rate	$ -	$ -	$ -	$ -	$ -	$ -
Demand Entitlement - MW	250	250	250	250	250	250
Maximum MB Monthly Pmt	$ -	$ -	$ -	$ -	$ -	$ -

Equivalent PF subject to same adjustments established for the PF rate.

CY MB Monthly Payments, Demand Entitlement Equals 250 MW

	Minimum Load Requirement	Maximum MB Monthly Payment	Actual Monthly Load (MWh)	Monthly Plant Load (aMW)	Meets Minimum Load Requirement?	MB Monthly Payment
October	46,563	$ -	63,000	84.6	**Yes**	$ -
November	45,000	$ -	61,000	84.7	**Yes**	$ -
December	46,500	$ -	60,000	80.6	**Yes**	$ -
January	46,500	$ -	44,500	59.8	**No**	$ -
February	42,000	$ -	40,500	60.3	**No**	$ -
March	46,500	$ -	45,000	60.5	**No**	$ -
April	44,938	$ -	44,000	61.2	**No**	$ -
May	46,500	$ -	46,000	61.8	**No**	$ -
June	45,000	$ -	60,000	83.3	**Yes**	$ -
July	46,500	$ -	80,000	107.5	**Yes**	$ -
August	46,500	$ -	90,000	121.0	**Yes**	$ -
September	45,000	$ -	97,500	135.4	**Yes**	$ -
		-	731,500			$ -

In this example the Forecast Market Price is less than the Equivalent PF so there are no MB Monthly Payments made to the DSI.

II. EXAMPLES OF THE DETERMINATION OF UNUSED BENEFIT AMOUNTS

Following are examples of the determination of Unused Benefit Amounts pursuant to section 7 of the body of this Agreement.

Example No. 1: DSI's operation without any UBA made available at the end of the 12 month period. Maximum Allocation equals 250 aMW and the MB Rate equals $18/MWh.

	Minimum Load Requirement	Maximum MB Monthly Payment	Actual Monthly Load (MWh)	Monthly Plant Load (aMW)	MB Monthly Payment	Maximun MB Monthly Payment Paid?	Percentage MB Payment Accessed
April	44,938	$ 2,157,000	130,000	180.8	$ 2,157,000	Yes	100.00%
May	46,500	$ 2,232,000	100,000	134.4	$ 1,800,000	-- No --	80.65%
June	45,000	$ 2,160,000	100,000	138.9	$ 1,800,000	-- No --	83.33%
July	46,500	$ 2,232,000	89,000	119.6	$ 1,602,000	-- No --	71.77%
August	46,500	$ 2,232,000	81,000	108.9	$ 1,458,000	-- No --	65.32%
September	45,000	$ 2,160,000	90,000	125.0	$ 1,620,000	-- No --	75.00%
October	46,563	$ 2,235,000	88,000	118.1	$ 1,584,000	-- No --	0.00%
November	45,000	$ 2,160,000	92,000	127.8	$ 1,656,000	-- No --	76.67%
December	46,500	$ 2,232,000	115,000	154.6	$ 2,070,000	-- No --	92.74%
January	46,500	$ 2,232,000	115,000	154.6	$ 2,070,000	-- No --	92.74%
February	42,000	$ 2,016,000	105,000	156.3	$ 1,890,000	-- No --	93.75%
March	46,500	$ 2,232,000	116,000	155.9	$ 2,088,000	-- No --	93.55%
		26,280,000.0	1,221,000		21,795,000		

No UBA is made available at the end of this 12month period because the DSI received a Maximum MB Monthly Payment in April but one more month without accessing the Maximum MB Monthly Payment will result in UBA; up to 6 percent of this DSI Maximum Allocation may be made available to the Other DSIs.

Example No. 2: DSI's operation with UBA resulting at the end of the 12-month period. Maximum Allocation/Demand Entitlement equals 250 aMW and the MB Rate equals $18/MWh.

	Minimum Load Requirement	Maximum MB Monthly Payment	Actual Monthly Load (MWh)	Monthly Plant Load (aMW)	MB Monthly Payment	Maximun MB Monthly Payment Paid?	Percentage MB Payment Accessed
April	44,938	$ 2,157,000	100,000	139.1	$ 1,800,000	-- No --	83.45%
May	46,500	$ 2,232,000	100,000	134.4	$ 1,800,000	-- No --	80.65%
June	45,000	$ 2,160,000	100,000	138.9	$ 1,800,000	-- No --	83.33%
July	46,500	$ 2,232,000	89,000	119.6	$ 1,602,000	-- No --	71.77%
August	46,500	$ 2,232,000	81,000	108.9	$ 1,458,000	-- No --	65.32%
September	45,000	$ 2,160,000	90,000	125.0	$ 1,620,000	-- No --	75.00%
October	46,563	$ 2,235,000	88,000	118.1	$ 1,584,000	-- No --	0.00%
November	45,000	$ 2,160,000	92,000	127.8	$ 1,656,000	-- No --	76.67%
December	46,500	$ 2,232,000	115,000	154.6	$ 2,070,000	-- No --	92.74%
January	46,500	$ 2,232,000	115,000	154.6	$ 2,070,000	-- No --	92.74%
February	42,000	$ 2,016,000	105,000	156.3	$ 1,890,000	-- No --	93.75%
March	46,500	$ 2,232,000	116,000	155.9	$ 2,088,000	-- No --	93.55%
		26,280,000.0	1,191,000		21,438,000		

In this example, the Maximum MB Monthly Payment was not accessed any month over the past 12 months. The DSI's Maximum Allocation times the highest percentage accessed (93.75%) over the pass 12 months rounded to the nearest aMW establishes its new Maximum Allocation (250 aMW * 0.9375 = 234.375 rounded to 234 aMW). UBA that will be made available to the Other DSIs is 250 aMW minus 234 aMW, 16 aMW.

Example No. 3: DSI's operation with UBA resulting at the end of the 12-month period. Maximum Allocation/Demand Entitlement equals 250 aMW and the MB Rate equals $12/MWh.

	Minimum Load Requirement Minus	Maximum MB Monthly Payment	Actual Monthly Load (MWh)	Monthly Plant Load (aMW)	MB Monthly Payment	Maximum MB Monthly Payment Paid?	Percentage MB Payment Accessed
April	44,938	$ 2,157,000	100,000	139.1	$ 1,200,000	-- No --	55.63%
May	46,500	$ 2,232,000	100,000	134.4	$ 1,200,000	-- No --	53.76%
June	45,000	$ 2,160,000	100,000	138.9	$ 1,200,000	-- No --	55.56%
July	46,500	$ 2,232,000	89,000	119.6	$ 1,068,000	-- No --	47.85%
August	46,500	$ 2,232,000	81,000	108.9	$ 972,000	-- No --	43.55%
September	45,000	$ 2,160,000	90,000	125.0	$ 1,080,000	-- No --	50.00%
October	46,563	$ 2,235,000	88,000	118.1	$ 1,056,000	-- No --	0.00%
November	45,000	$ 2,160,000	92,000	127.8	$ 1,104,000	-- No --	51.11%
December	46,500	$ 2,232,000	115,000	154.6	$ 1,380,000	-- No --	61.83%
January	46,500	$ 2,232,000	115,000	154.6	$ 1,380,000	-- No --	61.83%
February	42,000	$ 2,016,000	105,000	156.3	$ 1,260,000	-- No --	62.50%
March	46,500	$ 2,232,000	116,000	155.9	$ 1,392,000	-- No --	62.37%

In this example, the Maximum MB Monthly Payment was not accessed any month over the past 12 months. The DSI's Maximum Allocation times the highest percentage accessed (62.50%) over the pass 12 months rounded to the nearest aMW establishes its new Maximum Allocation (250 aMW * 0.62.50 = 156.25 rounded to 156 aMW). UBA that will now be made available to the Other DSIs is 250 aMW minus 156 aMW, 94 aMW.

III. EXAMPLES OF THE ACQUISITION OF UNUSED BENEFIT AMOUNTS

Following are examples of the acquisition of Unused Benefit Amounts pursuant to section 8 of the body of this Agreement.

Example No. 1: Maximum Allocation increases of two DSI who both increased operation to acquire nearly all available UBA (94 aMW).

	DSI-A Maximum Allocation	DSI-B Maximum Allocation	UBA Available aMW	UBA Acquired by DSI-A	UBA Acquired by DSI-B
April	140	100	94	50	39
May	190	139	5	0	0
June	190	139	5	0	0
July	190	139	5	0	0
August	190	139	5	0	0
September	190	139	5	0	0
October	190	139	0	0	0
November	190	139	0	0	0
December	190	139	0	0	0
January	190	139	0	0	0
February	190	139	0	0	0
March	190	139	0	0	0

In this example DSI-A was allocated 50 aMW and DSI-B was allocated 39 aMW. The new Demand Entitlement for DSI-A is 190 aMW and 139 aMW for DSI-B. The remaining 5 aMW of UBA was never acquired and after September was not available to any DSIs.

Example No. 2: Same as Example #1 except DSI-A has a contractually limited Maximum Allocation of 171 aMW.

	DSI-A Maximum Allocation	DSI-B Maximum Allocation	UBA Available aMW	UBA Acquired by DSI-A	UBA Acquired by DSI-B
April	140	100	94	31	39
May	171	139	24	0	0
June	171	139	24	0	0
July	171	139	24	0	0
August	171	139	24	0	0
September	171	139	24	0	0
October	171	139	0	0	0
November	171	139	0	0	0
December	171	139	0	0	0
January	171	139	0	0	0
February	171	139	0	0	0
March	171	139	0	0	0

In this example DSI-A's Demand Entitlement was limited to 171 aMW. DSI-A was allocated 31 aMW and DSI-B was allocated its 39 aMW of UBA. Available UBA was 24 aMW through September but because none was acquired during this period it was no longer available to any DSIs afterward.

Example No. 3: Maximum Allocation of two DSIs increased over 2-month period with full amount of UBA (94 aMW) allocated.

	DSI-A Maximum Allocation	DSI-B Maximum Allocation	UBA Available aMW	UBA Acquired by DSI-A	UBA Acquired by DSI-B
April	140	100	94	0	45
May	140	145	49	24	25
June	164	170	0	0	0
July	164	170	0	0	0
August	164	170	0	0	0
September	164	170	0	0	0
October	164	170	0	0	0
November	164	170	0	0	0
December	164	170	0	0	0
January	164	170	0	0	0
February	164	170	0	0	0
March	164	170	0	0	0

In this example DSI-B increased its load in April sufficient to acquire 45 aMW of the available UBA, resulting in its Maximum Allocation increasing from 100 aMW to 145 aMW beginning with May. Both DSIs increased load sufficiently for the remaining UBA to be allocated during May, increasing DSI-A's Maximum Allocation to 164 aMW and DSI-B's Maximum Allocation to 170 aMW.

Exhibit E
MAXIMUM ALLOCATION, MINIMUM ALLOCATION, AND DEMAND ENTITLEMENT

1. MAXIMUM AND MINIMUM ALLOCATIONS

During periods when Monetary Benefit payments are provided pursuant to section 6 of the body of this Agreement, the Maximum Allocation, Minimum Allocation, and Monetary Benefit Limit amounts are as follows:

Maximum Allocation:	320 aMW
Minimum Allocation:	80 aMW
Monetary Benefit Limit:	$33,638,400/CY (Leap Year $92,160 greater.)

2. DEMAND ENTITLEMENT

During periods when this Agreement operates as a physical Surplus Firm Power sale pursuant to section 4 of the body of this Agreement, the Demand Entitlement shall be as follows:

Demand Entitlement:	320 MW

3. **REVISIONS**

BPA shall unilaterally revise this Exhibit E to reflect changes to Maximum Allocation, Minimum Allocation, Monetary Benefit Limit, and/or Demand Entitlement.

Exhibit F
DETERMINATION OF FORECAST MARKET PRICE AND EQUIVALENT PF

1. DETERMINATION OF FORECAST MARKET PRICE

Prior to the beginning of each Contract Year, the following provisions shall be used to determine the Forecast Market Price.

(a) **Definitions**

(1) **“2007-2011 Agreements”** means the agreements between BPA and each PNW IOU that provide for among other things, the determination of the Forward Flat-Block Price Forecast for each year, 2007 through 2011.

(2) **“FBPF Exhibit”** means the exhibit titled “Determination of Forward Flat-Block Price Forecast For Contract Years 2007 through 2011, which is attached to each of the 2007-2011 Agreements.

(3) **"Forward Flat-Block Price Forecast"** or **"FBPF"** means the Forward Flat-Block Price Forecast developed from time to time under the 2007-2011 Agreements.

(4) **“Forward Price Data Agreement”** means BPA Contract No. 04PB-11534 among BPA and the PNW IOUs.

(5) **“PNW Investor-Owned Utility”** or **“PNW IOU”** means each of the following investor-owned utilities (and its investor-owned utility successors and assigns) that serves residential and small farm customers in the Pacific Northwest: Puget Sound Energy, Inc., PacifiCorp, Portland General Electric Company, Avista Corporation, Idaho Power Company, and NorthWestern Energy Division of NorthWestern Corporation.

(b) **Determination of Forecast Market Price**

(1) BPA has contracted with a qualified third party (QTP) pursuant to the FBPF Exhibit to determine the Forward Flat-Block Price Forecast for each Contract Year, 2007 through 2011.

(2) During four consecutive quarters prior to the beginning of each Contract Year, 2007 through 2011, the QTP surveys certain eligible data providers (EDPs) that have signed contracts in the form of Exhibit A to the Forward Price Data Agreement.

(3) The first quarterly survey for CY 2007 is conducted during Q1 of calendar year 2005 (January 2005-March 2005). The last quarterly survey for CY 2007 is conducted during Q4 of calendar year 2005 (October 2005-December 2005). The same procedure is followed for CY 2008 through 2011 but the quarters surveyed change to calendar

years 2006 through 2009, respectively. Each quarterly survey results in an FBPF for the upcoming CY. The average of the four quarterly FBPFs is the FBPF that is used to calculate benefits under the 2007-2011 Agreements.

(4) For the purpose of determining Monetary Benefit pursuant to section 6 of the body of this Agreement, the Forecast Market Price shall be equal to the FBPF established for Q4 of each calendar year for the upcoming CY. For example, the FBPF for Q4 of calendar year 2005 shall be the Forecast Market Price for CY 2007.

The Forecast Market Price for CY 2007 is $67.75/MWh.

2. DETERMINATION OF EQUIVALENT PF

Prior to the beginning of each CY, BPA will calculate the initial Equivalent PF for each such CY and, if applicable, for the Option Period.

(a) For Monetary Benefits not included in Option Benefits the Equivalent PF shall be equal to the actual cost, in $/MWh, to purchase 1 MW during every hour of the CY at the PF Rate (including but not limited to the effect of any adjustments, surcharges, dividends or true-ups) divided by the number of hours in the CY.

(b) For Monetary Benefits included in Option Benefits the Equivalent PF for the Option Period shall be the weighted average of the Equivalent PF for each CY included in whole or part within the Option Period calculated as follows: (i) For each CY within the Option Period, a CY Total Plant Load will be calculated by summing the monthly Total Plant Loads for each month of the CY that falls within the Option Period. For this calculation monthly Total Plant Load shall be limited to the Maximum Allocation, less UBA amounts not included in Option Benefits, and will be deemed equal to zero if the monthly Total Plant load is less than the Minimum Allocation. (ii) Each CY Total Plant Load for each CY from step i will then be multiplied by the Equivalent PF for the corresponding CY. (iii) The sum of the numbers calculated in step ii will then be divided by the sum of the CY Total Plant Loads from step i for the entire Option Period to derive the Equivalent PF for the Option Period. For purposes of this calculation, if the Option Period extends beyond CY 2009, BPA will deem the Equivalent PF Rate equal to a rate that results in an MB Rate, for periods beyond the CY 2009, equal to $24/MWh until BPA's initial proposal is published for the FY 10-11 Rate Period. When the initial proposal for FY 10-11 Rate Period is published the Equivalent PF used in this calculation for CY 2010 and CY 2011 will be established according to 2(c) below.

(c) Each time any adjustment, surcharge, dividend or true-up to the PF Rate is proposed by BPA in writing (which may be before the date such change will actually be applied to the PF Rate), BPA will adjust the Equivalent PF and the MB Rate and MB Monthly Payments for the remaining months of such CY or Option Period. Such adjustment will take into consideration the

Monetary Benefits provided to date and the PF Rate adjustment to provide an end-of-CY or end of Option Period total Monetary Benefit to which Alcoa is entitled. If such recalculation indicates that BPA has paid Alcoa more in Monetary Benefits than the amount to which Alcoa is entitled, then BPA will reduce the MB Monthly Payments to Alcoa over the next following three months (if full recovery of the amount is not possible in the 3-month period BPA may invoice Alcoa for the remaining amount), by the amount needed to recover the overpayment. If adjustments, surcharges, and true-ups are established after the CY or Option Period ends, then BPA will calculate the final Equivalent PF rate for each such CY or Option Period, and adjustments to Monetary Benefit will be applied in the following CY.

(d) If, upon termination of this Agreement, a true-up or other adjustment following the end of the final CY results in a payment owed by Alcoa to BPA, then BPA shall invoice Alcoa for such payment within 90 days following the end of such final CY. Such payment shall be made by Alcoa within 20 days following the receipt of such invoice. If, upon termination of this Agreement, a true-up or other adjustment following the end of the final CY results in a payment owed by BPA to Alcoa, then BPA shall pay Alcoa no later than 90 days following the end of such final CY.

3. REVISIONS

BPA shall have the unilateral right to revise this Exhibit F to reflect the Forecast Market Price and Equivalent PF for each CY after CY 2007 calculated pursuant to this Exhibit F. Any changes to the procedure used to determine Forecast Market Price or Equivalent PF may only be made upon mutual agreement of the Parties.

Attachment G

Contract No. 06PB-11745, Power Sale to CFAC (June 2006)

Contract No. 06PB-11745

AUTHENTICATED

BLOCK POWER SALES AGREEMENT
executed by the
BONNEVILLE POWER ADMINISTRATION
and
COLUMBIA FALLS ALUMINUM COMPANY, LLC
and
FLATHEAD ELECTRIC COOPERATIVE, INC.

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This BLOCK POWER SALES AGREEMENT (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA), COLUMBIA FALLS ALUMINUM

COMPANY, LLC (CFAC), and FLATHEAD ELECTRIC COOPERATIVE, INC. (Flathead). CFAC is a corporation organized under the laws of the State of Delaware. Flathead is a nonprofit corporation organized under the laws of the State of Montana. BPA, CFAC, and Flathead are sometimes referred to in the singular as "Party" or in the plural as "Parties."

RECITALS

On June 30, 2005, BPA issued a record of decision titled "Bonneville Power Administration's Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011." On May 31, 2006, BPA issued a supplement to the record of decision. The record of decision and its supplement together constitute and are referred to herein as the Administrator's ROD.

This Agreement implements the decisions contained in the Administrator's ROD.

BPA has administratively divided its organization into two business lines in order to functionally separate the administration and decision making activities of BPA's power business from the administrative and decision making activities of its transmission business. References in this Agreement to the Power Business Line (PBL) are solely for the purpose of establishing which BPA business line is responsible for the administration of this Agreement.

BPA, CFAC and Flathead agree:

1. TERM

This Agreement, when signed by the Parties, shall become effective on October 1, 2006, and shall continue in effect through September 30, 2011, unless terminated earlier pursuant to section 16 below. All obligations incurred hereunder shall be preserved until satisfied.

2. DEFINITIONS

Capitalized terms in this Agreement shall have the meanings defined below, in the exhibits or in context. All other capitalized terms and acronyms are defined in BPA's applicable Wholesale Power Rate Schedule(s), including the General Rate Schedule Provisions (GRSPs).

(a) "Business Day" means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principle place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

(b) "Contract Year" or "CY" means the period that begins each October 1 and which ends the following September 30. For instance, CY 2007 begins October 1, 2006, and continues through September 30, 2007.

(c) "Demand Entitlement" means, during periods when this Agreement operates as a physical Surplus Firm Power sale, the megawatt (MW) amount each hour that Flathead shall purchase from PBL, and that CFAC shall purchase from Flathead, as specified in Exhibit E.

(d) "Equivalent PF" means the applicable average Priority Firm Rate at 100 percent load factor, as determined pursuant to Exhibit F.

(e) "Escrow Account" means the specific account established pursuant to the provisions in section 9(b) below for receipt of funds from BPA and transfer of funds by Flathead to CFAC.

(f) "Forecast Market Price" means the annual forecast market price for power at 100 percent load factor, as determined pursuant to the procedures in Exhibit F or, if CFAC has selected an option pursuant to subsection 5(c) or subsections 5(c) and 5(d), then as determined by the average purchase price paid by CFAC during the Option Period.

(g) "FY 07-09 Rate Period" means the wholesale power rate period that begins on October 1, 2006, and continues through September 30, 2009.

(h) "FY 10-11 Rate Period" means the wholesale power rate period that begins on October 1, 2009, and continues through September 30, 2011.

(i) "MB Monthly Payment" means the monthly Monetary Benefit payment that is available during each month, as calculated in section 6(c)(4) below.

(j) "MB Rate" means the rate in dollars per megawatt-hour ($/MWh) used to calculate MB Monthly Payments pursuant to section 6(c) below. The MB Rate is determined by subtracting Equivalent PF from Forecast Market Price, and shall not exceed $24/MWh.

(k) "Maximum Allocation" means, for the purpose of determining MB Monthly Payments, the maximum average megawatt (aMW) amount that may be used to determine a MB Monthly Payment. The Maximum Allocation is shown in Exhibit E.

(l) "Maximum MB Monthly Payment" means the amount calculated in section 6(c)(3) below.

(m) "Minimum Allocation" means, for the purpose of determining MB Monthly Payments, the minimum aMW amount that may be used to determine a MB Monthly Payment. The Minimum Allocation is equal to one-fourth of the Maximum Allocation.

(n) "Monetary Benefits" means monetary payments made by BPA to Flathead for the account of CFAC under this Agreement, as determined pursuant to the provisions in section 6 below.

(o) “Monthly Plant Load” means a monthly aMW amount equal to the Total Plant Load for each month divided by the number of hours in each such month.

(p) “Monthly Purchase Deficiency” means the monthly amount(s) of Surplus Firm Power not purchased due to a curtailment, as such amount(s) may be adjusted pursuant to section 4(e)(1) below.

(q) “Northwest Power Act” means the Pacific Northwest Electric Power Planning and Conservation Act of 1980, P.L. 96-501.

(r) “Option Benefits” means the MB Monthly Payments under the options provided for in section 5(c) and 5(d), including UBA amounts if CFAC chooses to establish Monetary Benefits pursuant to the provisions to include UBA in Option Benefits as specified in section 8(a)(4) below.

(s) “Option Period” means the combined period(s) of the option(s) specified in the provisions of section 5(c) and 5(d) selected by CFAC to establish MB Monthly Payments

(t) “Other DSIs” means aluminum smelters other than CFAC that have executed an agreement substantially in the form of this Agreement.

(u) “Points of Measurement” means the interconnection points between BPA, CFAC, and other control areas, as applicable. Electric power amounts are established at these points based on metered amounts or scheduled amounts, as appropriate.

(v) "Point of Receipt" means the points of interconnection on the transmission provider's transmission system where Surplus Firm Power shall be made available by PBL to Flathead, and where Surplus Firm Power shall be made available by Flathead to CFAC’s transmission provider.

(w) “Power Business Line” or “PBL” means that portion of the BPA organization or its successor that is responsible for the management and sale of BPA’s Federal power.

(x) “Region” means the definition established for “Region” in the Northwest Power Act.

(y) “Surplus Firm Power” means electric power that PBL shall make continuously available to Flathead, and which Flathead shall make continuously available to CFAC, under this Agreement.

(z) “Total Plant Load” means the amount of electric energy in megawatt-hours (MWh) consumed during each month at CFAC’s production facilities. A detailed description of CFAC’s production facilities, including station service requirements and metering equipment, is described in Exhibit B.

(aa) "Transmission Business Line" or "TBL" means that portion of the BPA organization or its successor that is responsible for the management and sale of transmission service on the Federal Columbia River Transmission System (FCRTS).

(bb) "Unused Benefit Amount" or "UBA" means either: (1) an aMW amount determined pursuant to section 7(a) during any period in which Monetary Benefits are provided, or (2) a MW amount determined pursuant to section 7(b) during any period in which this Agreement operates as a physical Surplus Firm Power sale.

3. APPLICABLE RATES

(a) **Applicable Rate for Purchases by Flathead**
Purchases by Flathead under this Agreement are subject to the Firm Power Products and Services (FPS) rate schedule or its successor, and the General Rate Schedule Provisions (GRSP). Purchases under the FPS rate schedule are established as follows:

If this Agreement operates as a physically delivered Surplus Firm Power sale pursuant to section 4 below, then section 4(a) below and Exhibit A, Surplus Firm Power Rate, identify Surplus Firm Power amounts, rates, and billing entitlements subject to the FPS rate schedule. If the Surplus Firm Power sale is monetized, then the provisions of section 6 below establish the applicable FPS rate.

(b) **Applicable Rate for Purchases by CFAC**
Purchases by CFAC under this Agreement are subject to the applicable rate schedule developed by Flathead for such purchases. The rates and billing entitlements specified in such rate schedule shall be equal to those rates billed to Flathead by BPA under this Agreement, FPS rate schedule and GRSPs, as specified in Exhibit A.

4. POWER SALE PROVISIONS

This section 4 only applies when this Agreement operates as a physically delivered Surplus Firm Power sale. In this event, the Monetary Benefit provisions in section 6 shall not apply. All physically delivered Surplus Firm Power provided by PBL under this section 4 is solely for service to Total Plant Load.

(a) **Power Sale by PBL to Flathead**

(1) **Hourly Amounts**
PBL shall make available and Flathead shall purchase the Demand Entitlement each hour. The Demand Entitlement is specified in Exhibit E.

(2) **HLH and LLH Energy Entitlements and Demand Entitlement**

The Demand Entitlement multiplied by: (A) the number of HLH; and (B) the number of LLH in the applicable month establishes Flathead's HLH and LLH Energy Entitlements with respect to this Agreement.

(b) **Power Sale by Flathead to CFAC**

(1) **Hourly Amounts**
Flathead shall make available and CFAC shall purchase the Demand Entitlement each hour. The Demand Entitlement is specified in Exhibit E.

(2) **HLH and LLH Energy Entitlements and Demand Entitlement**
The Demand Entitlement multiplied by: (A) the number of HLH; and (B) the number of LLH in the applicable month establishes CFAC's HLH and LLH Energy Entitlements.

(c) **Unauthorized Increase Charge**
CFAC shall not intentionally schedule in excess of the amount specified in section 4(b)(1) above. However, in the event that an excess amount is scheduled due to error, then such amounts taken by CFAC from Flathead at the Points of Receipt in excess of the amounts specified in section 4(b)(2) above shall be subject to the Unauthorized Increase Charge for demand and energy consistent with the applicable BPA Wholesale Power Rate Schedules and GRSPs, unless such power is provided under another contract with PBL. Power that has been provided for energy imbalance service pursuant to an agreement between TBL and CFAC shall not be subject to an Unauthorized Increase Charge for Demand and Energy under this Agreement. Any Unauthorized Increase Charge shall be billed by BPA in accordance with the billing procedures described in section 9(a) below. Any Surplus Firm Power used by Flathead or CFAC for any other purpose shall be subject to the Unauthorized Increase Charge.

(d) **Curtailment**
If CFAC curtails Total Plant Load in whole or in part, then CFAC may request take-or-pay mitigation for purchases under section 4(b) above pursuant to section 4(e) below.

(e) **Take-or-Pay Mitigation for Curtailments**
If CFAC chooses to curtail its purchase obligation, then the following terms and conditions shall apply:

(1) **Notice of Curtailment**
CFAC shall provide written notice to PBL and Flathead at least three (3) Business Days in advance of a curtailment. Such notice shall specify the monthly amounts of power to be curtailed and the duration of the curtailment. The election to curtail such power, and the amount and duration of such curtailment, may not be changed without PBL's consent. PBL's sale to Flathead shall be reduced by the amount of power curtailed, and Flathead shall not be assessed any damages or

incur any liability as a result of any such reduction. The Monthly Purchase Deficiency will be reduced by any reduction to the Demand Entitlement pursuant to section 7(b)(2) below.

(2) **Calculation of Damages**
CFAC shall pay directly to BPA damages for each Monthly Purchase Deficiency equal to the amount by which the reasonable market value of such Monthly Purchase Deficiency is less than the price of the applicable rate specified in Exhibit A. For purposes of calculating damages under this section 4(e)(2), the Monthly Purchase Deficiency(s) shall be reduced by any reduction of Demand Entitlement under section 7(b)(3), effective on the date any such reduction becomes effective. No later than 60 days following the end of each Contract Year, PBL shall, for each month of the previous Contract Year, calculate the reasonable market value for each Monthly Purchase Deficiency during such Contract Year. Reasonable market value and calculation of damages shall be determined as follows.

(A) No later than 3 Business Days prior to the commencement of a curtailment under this section 4(e), CFAC may obtain one or more transactable quotes for all or a portion of such power from a third party. The transactable quote may be for any length of time and curtailment amount. Each quote shall be deemed equal to the reasonable market value of such power to which the quote applies for the purpose of calculating damages under this section 4(e)(2). BPA may, but shall not be obligated to, resell the curtailed power to the third party, retain the power, or dispose of the power as it chooses. CFAC shall allow PBL at least 4 hours during normal business hours to decide whether or not to transact under such quote.

(B) BPA shall determine, by any reasonable method, the reasonable market value of the portion of each Monthly Purchase Deficiency for which CFAC has not obtained a transactable quote. The reasonable market value shall be adjusted to reflect volume and BPA transmission costs associated with remarketing each such portion of the Monthly Purchase Deficiency, regardless of whether each such portion is actually remarketed.

(C) BPA shall bill CFAC and CFAC shall directly pay BPA damages for such Contract Year equal to the amount by which the sum of the product of (1) each Monthly Purchase Deficiency and (2) the applicable rate specified in Exhibit A that BPA would have charged each month if the power had been taken under this Agreement, exceeds the sum of the product of (1) each Monthly Purchase Deficiency and (2) the reasonable market value in each month. Amounts for damages under section 4(e)(2)(A) and section 4(e)(2)(B) may only be netted within a Contract Year. If a transactable quote for a curtailment or portion of a curtailment extends into a future Contract Year, then the total amounts associated with such quote will be netted in the Contract Year in which the curtailment or portion of curtailment associated with such quote begins. BPA is not obligated to pay CFAC the difference when the reasonable market value exceeds the applicable rate in Exhibit A.

It is expressly agreed to by the Parties that BPA shall not be obligated to enter into replacement transactions to determine or collect damages under this section 4(e)(2).

It is also expressly agreed that BPA will apply its then-current applicable credit policies if damages are due under this section 4(e)(2), and such policies may include an obligation to prepay for damages.

(f) **Scheduling**
All Surplus Firm Power transactions under this Agreement shall be scheduled and implemented consistent with Exhibit C, BPA Power Business Line Scheduling Provisions. The procedures for scheduling described in Exhibit C are the standard utility procedures followed by BPA for power transactions between PBL and other utilities or entities in the Region that require scheduling.

(g) **Delivery**

(1) **Transmission Service for Surplus Firm Power**
This Agreement does not provide transmission services for, or include the delivery of, Surplus Firm Power by BPA to Flathead, or by Flathead to CFAC. CFAC shall be responsible for executing one or more wheeling agreements with a transmission supplier for the delivery of Surplus Firm Power (Wheeling Agreement). PBL and CFAC agree to take such actions as may be necessary to facilitate the delivery of Surplus Firm Power to CFAC, consistent with the terms, notice, and the time limits contained in the Wheeling Agreement.

(2) **Liability for Delivery**
CFAC waives any claims against PBL and Flathead arising under this Agreement for nondelivery of power to any points beyond the applicable Points of Receipt. Neither Flathead nor PBL shall be liable for any third-party claims related to the delivery of power after it leaves the Points of Receipt. In no event shall any Party be liable under this Agreement to any other Party for damage that results from any sudden, unexpected, changed, or abnormal electrical condition occurring in or on any electric system, regardless of ownership. These limitations on liability apply regardless of whether or not this Agreement provides for transfer service.

(3) **Points of Receipt**

PBL shall make Surplus Firm Power available to Flathead, and Flathead shall make Surplus Firm Power available to CFAC under this Agreement at Points of Receipt solely for the purpose of CFAC scheduling transmission to points of delivery for service to CFAC's Total Plant Load. CFAC shall schedule, if scheduling is necessary, such Surplus Firm Power solely for use by its Total Plant Load. PBL, for purposes of scheduling transmission for delivery under this Agreement, shall specify Points of Receipt in a written notice to Flathead and CFAC no later than October 1, 2008.

If required by the Wheeling Agreement, when PBL designates such Points of Receipt, PBL shall provide capacity amounts for transmission under the Wheeling Agreement associated with the initial Points of Receipt that can be accepted as firm Points of Receipt under CFAC's Wheeling Agreement (except in the event that all Points of Receipt on the Federal Columbia River Power System (FCRPS) would be considered nonfirm). The sum of capacity amounts requested by PBL shall not exceed the amount of Surplus Firm Power specified in sections 4(a) and 4(b) above. Such Points of Receipt and their capacity amounts may only be changed through mutual agreement. However, at any time PBL may request the use of a nonfirm Point of Receipt to provide Surplus Firm Power to Flathead for the account of CFAC, but notwithstanding section 4(g)(2) above, PBL shall reimburse CFAC for any additional costs or production losses incurred by CFAC due to its compliance with such request.

(4) **Transmission Losses**

PBL shall provide CFAC the transmission losses between the Points of Receipt and CFAC's points of delivery for Surplus Firm Power, at no additional charge. Such losses shall be provided at Points of Receipt as established under section 4(g)(3) above, and under the terms and conditions as defined in the transmission provider's tariff.

(h) **Measurement**

(1) Amounts of Surplus Firm Power taken are deemed equal to the amount scheduled by CFAC under section 4(f) above or an amount of power as measured at Points of Measurement, as appropriate.

(2) CFAC shall provide reasonable notice to PBL and Flathead prior to changing control areas.

(i) **Interruption Rights**

PBL shall have a one-time right during the term of this Agreement to interrupt deliveries of a portion of the Surplus Firm Power hereunder pursuant to the following provisions. PBL may interrupt a portion of Surplus Firm Power deliveries if PBL anticipates, in its sole and exclusive discretion, that average forward market prices for a flat block of power will exceed $125/MWh during an interruption period to be specified by PBL in a written notice. In this event, PBL shall consult with CFAC and Flathead prior to providing such written notice. If PBL decides to interrupt, then it will provide 90 days advance written notice to CFAC and Flathead that specifies the amount of Surplus Firm Power to be interrupted and the associated interruption period; *provided, however,* that a minimum of 6 aMW will not be subject to any such interruption. Unless the Parties mutually agree otherwise, such interruption period shall extend for a minimum of 6 months and for a maximum of 12 months, regardless of the level of actual market prices during an interruption period. In the event of an interruption, BPA shall pay Flathead, and Flathead shall in turn pay CFAC, $24/MWh for amounts interrupted. Payments shall be made pursuant to section 9(b) below. Payments to CFAC under this section 4(i) shall be used first to compensate CFAC's employees employed at the time of an interruption under this section 4(i) by providing each such employee, at the election of CFAC, either (1) the opportunity to work a regular work week (40 hours) at regular wage and benefit rates, or (2) special supplemental benefits such that the employee's effective after-tax income (including any available unemployment income) will be equal to what the employee's income would have been working a regular work week, plus all benefits the employee would have received, had the employee been working a regular 40-hour work week. BPA shall have the right to conduct an audit to verify compliance with this section 4(i). If there is an interruption under this section 4(i), then the portion of Demand Entitlement interrupted shall be treated as if taken for purposes of section 7(b)(1)(A) and shall not be subject to the take-or-pay provisions in sections 4(a) and 4(b).

(j) **Modification of Flathead's Obligations**

(1) Flathead shall have no obligation to purchase any power from BPA under this Agreement except for such power that CFAC is obligated to and does purchase from Flathead under this Agreement. Flathead shall have no obligation to make available to CFAC any power under this Agreement except for such power that BPA is obligated to and does make available to Flathead under this Agreement. Notwithstanding anything in this Agreement to the contrary, if the obligation of BPA to make available power to Flathead or the obligation of CFAC to purchase power from Flathead are modified for any reason, including but not limited to curtailment, interruption or any change to the Demand Entitlement, then Flathead's corresponding obligation to make power available to CFAC and/or to purchase power from BPA shall be modified to the same extent.

(2) Flathead's obligation to purchase power from BPA and Flathead's obligation to make power available to CFAC are contingent upon CFAC performing its corresponding obligation's under this Agreement to purchase power from Flathead and upon BPA performing its corresponding obligation to make power available to Flathead.

Flathead's obligations under this Agreement to BPA and CFAC shall be excused and reduced to the extent of any nonperformance by CFAC or BPA of their corresponding obligations under this Agreement to Flathead.

5. BPA AND CFAC OPTIONS

(a) **Monetary Benefits for the FY 07-09 Rate Period**
BPA has determined that, during the FY 07-09 Rate Period, in order to meet the cost caps described in the Administrator's ROD with certainty, it will monetize the physically delivered Surplus Firm Power sale obligation; provided, however, if CFAC chooses an option specified in section 5(c) or 5(d) and/or 8(a)(4) below, then the physically delivered Surplus Firm Power sale obligation will be monetized for the entire Option Period. As such, BPA will make any MB Monthly Payments during the FY 07-09 Rate Period, the FY 10-11 Rate Period or the CY 2011 period, as applicable, subject to the provisions of section 5(c), 5(d), and 6 below.

(b) **BPA Option for the FY 10-11 Rate Period and the CY 2011 period**
PBL shall have the option to discontinue Monetary Benefits after the FY 07-09 Rate Period and to revert to a physically delivered Surplus Firm Power sale for the FY 10-11 Rate Period or for the CY 2011 period. This option is not applicable to the portion of MB Monthly Payments which CFAC has chosen to lock in under section 5(c), 5(d), and/or 8(a)(4). If PBL chooses to exercise this option, then BPA shall provide written notice to CFAC and Flathead no later than October 1, 2008. In this event, the provisions of section 6 below shall not apply to that portion of Monetary Benefits that have reverted to a physically delivered Surplus Firm Power sale during the period this option is applicable, and this Agreement will operate in whole or in part as a physically delivered Surplus Firm Power sale, subject to the provisions of section 4 above, unless CFAC elects to terminate this Agreement pursuant to section 16(b) below. In addition, in the event of a physical power sale, BPA will require CFAC to provide performance assurances, consistent with BPA's then-current applicable credit policies.

Prior to exercising this option BPA shall conduct a public process providing an opportunity for customers to comment on the merits of exercising the option.

(c) **CFAC Option for CY 2007-2009, CY 2007-2010 or CY 2007-2011**
CFAC shall have a one time option to establish its MB Monthly Payments for CY 2007-2009, CY 2007-2010, or CY 2007-2011 pursuant to this section 5(c). If this option is selected by CFAC, then the lower of the Forward Flat-Block Price Forecast, in effect on the date CFAC provides written notice pursuant to this section 5(c), or the average purchase price paid for power to serve CFAC's Total Plant Load during the Option Period shall establish the Forecast Market Price when calculating CFAC's MB Monthly Payments as specified in section 6 below. The power purchase contracts entered into by CFAC shall cover the full term of the Option Period and, except for UBA

amounts subject to section 8(a)(4), shall be for all power included in the Monetary Benefit calculation during the Option Period. If CFAC chooses to exercise this option, then CFAC shall provide written notice to BPA and Flathead no later than September 30, 2006, specifying the CY 2007-2009, CY 2007-2010 or CY 2007-2011 period for which it has selected this option. In such event, the provisions of section 6(c)(6) shall not apply to Monetary Benefits subject to this option during the Option Period. Within 30 days of providing such notice CFAC shall provide BPA access to contracts, invoices, or other documents reasonably necessary for BPA to verify the purchase price of power used to calculate CFAC's MB Monthly Payments for this option.

(d) **CFAC Option for CY 2010-2011 and CY 2011**
Provided CFAC exercised either the CY 2007-2009 option or the CY 2007-2010 option specified in section 5(c) CFAC shall also have a one time option to establish its MB Monthly Payments for the remainder of the Agreement. If CFAC selects this option, then the lower of the Forward Flat-Block Price Forecast, in effect on the date CFAC provides written notice pursuant to this section 5(d), or the average purchase price paid for power to serve CFAC's Total Plant load during the Option Period shall establish the Forecast Market Price when calculating CFAC's MB Monthly Payment specified in section 6 below. The power purchase contracts entered into by CFAC shall cover the full term of the Option Period and, except for UBA amounts subject to section 8(a)(4), shall be for all power included in the Monetary Benefit calculation during the Option Period. If CFAC chooses to exercise this option, then CFAC shall provide written notice to BPA and Flathead no later than September 30, 2007. In such event, the provisions of section 6(c)(6) shall not apply to Monetary Benefits subject to this option during the Option Period. Within 30 days of providing such notice, CFAC shall provide BPA access to contracts, invoices, or other documents reasonably necessary for BPA to verify the purchase price of power used to calculate CFAC's MB Monthly Payments for this option.

6. MONETARY BENEFIT PROVISIONS

This section 6 only applies when the physically delivered Surplus Firm Power sale is monetized. The provisions in section 4 shall not apply to Monetary Benefits.

(a) **Determination of Forecast Market Price and Equivalent PF for each CY or Option Period**
PBL shall determine the Forecast Market Price and Equivalent PF for each CY, using the procedures described in Exhibit F: provided, however, if CFAC selects any option specified in section 5(c) or 5(d), then the Forward Market Price shall be determined as specified in the option(s) selected by CFAC during the Option Period.

(b) **Determination of Monthly Plant Load**
No later than five (5) Business Days following the end of each month, PBL shall determine the Monthly Plant Load for each such month.

(c) **Determination of MB Monthly Payments**
Except as provided for in section 6(c)(5) below, the procedures described in Exhibit F and the following procedure, as described in sections 6(c)(1) through 6(c)(4), shall be used to determine the MB Monthly Payment for each month.

(1) Except as provided in section 6(c)(5), if the Monthly Plant Load is less than the Minimum Allocation during any month (Deficient Month), then the MB Monthly Payment for that month is $0.

(2) If the Monthly Plant Load is equal to or greater than the Maximum Allocation during any month, then the Monthly Plant Load shall be deemed equal to the Maximum Allocation for that month.

(3) The Maximum MB Monthly Payment for each month is determined by the following equation:

Maximum MB Monthly Payment = ((Maximum Allocation) x (number of hours in month)) x (lesser of $12/MWh or MB Rate);

provided, however, during the FY 07-09 Rate Period MB Monthly Payments for Option Benefits shall be determined by the following equation;

Maximum MB Monthly Payment = ((Maximum Allocation) x (number of hours in month)) x (lesser of $12/MWh x 0.92 or MB Rate).

(4) The MB Monthly Payment for each month shall be the lesser of the Maximum MB Monthly Payment determined pursuant to section 6(c)(3) above or the amount determined by the following equation:

MB Monthly Payment = ((Monthly Plant Load) x (number of hours in the month)) x (MB Rate)

(5) CFAC may exercise the following one-time option. If CFAC desires to exercise its one-time option pursuant to this section 6(c)(5), then CFAC shall provide written notice to PBL and Flathead that it will increase smelting load as of a date specified by CFAC in such notice (Start Date). Then, for the remainder of the month that includes the Start Date and the following 2 months, the MB Monthly Payment shall be determined by the following equation:

MB Monthly Payment = (Total Plant Load) x MB Rate

Each MB Monthly Payment determined under this section 6(c)(5) shall not exceed the Maximum MB Monthly Payment.

(6) In addition to other limitations specified in the Agreement, CFAC is only entitled to Monetary Benefits which when subtracted from the amount equal to its power costs to serve its Total Plant Load during the CY, does not reduce its power cost below the Equivalent PF multiplied by such total amount of power. If at any time during a Contract Year CFAC knows it has procured power at a cost that will result in less than the full Monetary Benefits to reach the Equivalent PF, then CFAC shall notify BPA of such cost and BPA shall reduce its payments accordingly for the remainder of the Contract Year.

This paragraph applies only for periods other than the Option Period, except with respect to acquired UBA not included in Option Benefits. Within 90 days following the end of each CY, BPA shall have the right to request: 1) Access to contracts, invoices or other documentation reasonably necessary for BPA to verify that purchases by CFAC of power equal to the sum of CFAC's Total Plant Loads for such CY and the cost of such purchases; and/or 2) A written certification from CFAC's CFO of power purchases by CFAC used to serve the sum of CFAC's Total Plant Loads for such CY and the cost of such purchases. CFAC shall provide BPA access to such contracts and documentation for such power purchases, subject to reasonable conditions to maintain the confidentiality of such information. If the difference between the cost of such purchases and their cost calculated as if they had been priced at the Equivalent PF is less than the sum of the Monetary Benefits that were paid to CFAC for such CY, then CFAC shall owe BPA such difference (Overpayment). BPA shall notify CFAC of any such Overpayment and will reduce the total Monetary Benefits in the CY following the CY in which the Overpayment occurred by the amount of such Overpayment. If the Overpayment exceeds Monetary Benefits available during that following CY, then any unrecovered Overpayment will carryover to reduce Monetary Benefits in subsequent years until fully recovered.

If, upon termination of this Agreement, an Overpayment occurred for the CY prior to such termination, then, within 90 days following the end of such CY, BPA shall invoice CFAC and CFAC shall pay BPA such Overpayment within 20 days of receipt of such invoice.

(7) Notwithstanding anything to the contrary in this Agreement, in no case shall the annual Monetary Benefit total exceed the Monetary Benefit Limit specified in Exhibit E of this Agreement.

(d) **Examples**
Section 1 of Exhibit D contains several illustrative examples of the calculation of MB Monthly Payments, using a variety of assumptions.

7. DETERMINATION OF UNUSED BENEFIT AMOUNTS

The following procedures shall be used to determine UBA.

(a) **Determination of Unused Benefit Amounts During Periods When Surplus Firm Power Sale is Monetized**
This section 7(a) only applies when the physically delivered Surplus Firm Power sale is monetized.

(1) Beginning in October 2007, and following each month thereafter, PBL shall track the amount of Monetary Benefit that CFAC has taken during each of the preceding 12 months.

(2) In order to retain its Maximum Allocation, CFAC must, for at least one month during the preceding 12 months, have received the Maximum MB Monthly Payment. If this condition has not been satisfied, then the Maximum Allocation shall be reduced.

(3) CFAC shall retain the highest monthly percentage of the available benefits that it accessed during the previous 12 months. As such, CFAC's Maximum Allocation shall be reduced by the percentage of the available benefits, rounded to the nearest aMW, that were not accessed during the month that set the highest monthly percentage. The amount of aMW from this calculation becomes an Unused Benefit Amount or UBA.

(4) In the event of an UBA, PBL shall provide written notice to CFAC and Flathead that CFAC's Maximum Allocation shall be reduced by the UBA. Such reductions shall become effective at 2400 hours on the last day of the month in the month the notice is provided (Date of Maximum Allocation Reduction). CFAC understands and agrees that it will not have an option to re-acquire UBA that it has lost for one month following the Date of Maximum Allocation Reduction and that Other DSIs may acquire the UBA. BPA shall unilaterally revise Exhibit E, effective on the Date of Maximum Allocation Reduction, to reflect the reduced Maximum Allocation. BPA shall also provide notice of the availability of the UBA to the Other DSIs.

(b) **Determination of Unused Benefit Amounts During Periods When the Surplus Firm Power Sale Is Physically Delivered**
This section 7(b) only applies when the Surplus Firm Power sale is physically delivered.

(1) In order to assure its right to retain its Demand Entitlement, as specified in Exhibit E, CFAC must, for at least one month during the preceding 12 months, have either (A) taken Surplus Firm Power equal to its Demand Entitlement during all hours of such month, or (B) taken the maximum Monetary Benefit available to it during such month. If this condition has not been satisfied, then the Demand Entitlement may be reduced.

(2) If the condition in section 7(b)(1) has not been satisfied, then BPA shall calculate the following for each of the previous 12 months:

(A) the percentage of the available Monetary Benefit received by CFAC, and (B) the percentage of the Demand Entitlement taken by CFAC. BPA may reduce the Demand Entitlement to the highest of such percentages multiplied by the Demand Entitlement, and rounded to the nearest MW. The MW amount of such reduction becomes an UBA.

(3) In the event of an UBA resulting from section 7(b)(2), PBL shall provide written notice to CFAC and Flathead that the Demand Entitlement may be reduced by the UBA. If all or a portion of such UBA is acquired by the Other DSIs pursuant to section 8(b) below, then the Demand Entitlement shall be reduced by the amount of UBA so acquired. Any such reduction shall become effective at 2400 hours on the last day of the month prior to the month that UBA has been acquired by the Other DSIs (Date of Demand Entitlement Reduction). BPA shall unilaterally revise Exhibit E, effective on the Date of Demand Entitlement Reduction, to reflect the reduced Demand Entitlement. If UBA made available under this section 7(b)(3) is not acquired by CFAC or the Other DSIs within 6 months following the date such UBA became available, then BPA may, but shall not be obligated to, revise Exhibit E unilaterally to reduce the Demand Entitlement by the UBA not acquired.

(4) If an UBA results from a termination of this Agreement pursuant to section 16(b) below, then the entire Demand Entitlement becomes an UBA as of the effective date specified in section 16(b) below. BPA shall provide notice of the availability of any UBA that becomes available under this section 7(b)(4) to the Other DSIs pursuant to the notice provisions in section 7(b)(3) above. The Other DSIs may acquire this UBA pursuant to section 8(b) below.

(5) If CFAC provides PBL and Flathead written notice of curtailment under section 4(e)(1) and UBA will result during the term of such curtailment by operation of sections 7(b)(1) and 7(b)(2), then for purposes of sections 7(b)(2) and 7(b)(3), the UBA that would result during the term of the curtailment shall become UBA upon commencement of the curtailment.

(c) **Examples**
Section 2 of Exhibit D contains several illustrative examples of the determination of UBA, using a variety of assumptions.

8. OPTION TO ACQUIRE UNUSED BENEFIT AMOUNTS

The following procedures shall be used to acquire UBA.

(a) **Option to Acquire Unused Benefit Amounts During Periods When the Physically Delivered Surplus Firm Power Sale is Monetized**
This section 8(a) only applies when the physically delivered Surplus Firm Power sale is monetized.

(1) Unless CFAC provides written notice to PBL and Flathead that it has chosen not to acquire UBA, available UBA amounts will be added to CFAC's Maximum Allocation, to the extent that doing so will increase the MB Monthly Payment it will receive for each month.

(2) During months when increases in Monthly Plant Load by CFAC and Other DSIs exceed the amount of UBA available, UBA will be allocated pro rata to CFAC and other DSIs, based on Maximum Allocation.

(3) BPA shall unilaterally revise Exhibit E to reflect the addition of acquired UBA in CFAC's Maximum Allocation and Monetary Benefit Limit.

(4) If CFAC has selected an Option Period under section 5(c) above, Monetary Benefits for the acquired UBA will not be included in calculations for Option Benefits and instead will be calculated separately under 6(c) above using the current Forecast Market Price as established under the provisions of Exhibit F of the Agreement unless and until CFAC notifies BPA it will include the acquired UBA in the calculations to establish the MB Monthly Payments for the remainder of the Option Period. If this option is selected, then the purchase price used as the Forecast Market Price in the calculation of the Option Benefits shall be based on a megawatt hour weighted average of: i) the average purchase price previously used to calculate the Option Benefits, and ii) the average purchase price for acquired UBA, provided that the average purchase price for acquired UBA shall be limited by the Forecast Market Price in effect at the time CFAC notifies BPA it will exercise this option.

If CFAC chooses to exercise this option, then CFAC shall provide written notice to BPA and Flathead of the purchase price for the power purchased to serve the acquired UBA. For purposes of calculating MB Monthly Payments, the starting date of the purchase shall be the beginning of the month following the notice. Power purchases under this option must begin no later than 6 months following the effective date of the revision to Exhibit E for such acquired UBA. The provisions of section 6(c)(6) shall not apply to these UBA amounts during the Option Period. Instead, within 30 days of providing its power purchase notice, CFAC shall provide BPA access to contracts, invoices, or other documents reasonably necessary for BPA to verify the purchase price of power used to calculate CFAC's MB Monthly Payments for this option.

(5) UBA amounts that remain available and unused for 6 months following the Date of Reduction shall be zeroed out and will no longer be available to CFAC or the Other DSIs during the term of this Agreement.

(b) **Option to Acquire Unused Benefit Amounts During Periods When the Surplus Firm Power is Physically Delivered**
This section 8(b) only applies when the Surplus Firm Power sale is physically delivered.

(1) Following receipt of a notice provided under section 7(b)(3) above, CFAC shall provide written notice to PBL and Flathead of the amount of UBA it wishes to purchase, if any.

(2) UBA amounts requested pursuant to section 8(b)(1) above will be added to the Demand Entitlement, effective on the first day of the month following receipt of the notice provided under section 8(b)(1) above.

(3) When requests for UBA by CFAC and Other DSIs exceed the amount of UBA available, UBA will be allocated pro rata to CFAC and other DSIs, based on Demand Entitlement.

(4) BPA shall unilaterally revise Exhibit E, effective on the date determined in 8(b)(2), to reflect an increase to the Demand Entitlement by the amount of acquired UBA.

(5) Any UBA acquired pursuant to this section 8(b) that remains unused after 6 months following the date specified in 8(b)(2) above will no longer be available to CFAC or the Other DSIs. Amounts of Total Plant Load during such 6-month period that are less than the increased Demand Entitlement shall become an unused UBA. Such unused UBA shall be considered a Monthly Purchase Deficiency for each month of the remaining term of this Agreement, and CFAC shall be subject to damages pursuant to section 4(e)(2) above.

(c) Any increased: (1) Maximum Allocation under section 8(a) above; or (2) Demand Entitlement under section 8(b) above shall not exceed 171 MW.

(d) Section 3 of Exhibit D contains several illustrative examples of the acquisition of UBA, using a variety of assumptions.

9. BILLING AND PAYMENT

(a) **Billing and Payment Provisions During Power Sale**
If, pursuant to section 5(b) above, BPA provides written notice that this Agreement will operate as a physically delivered Surplus Firm Power sale during the FY 10-11 Rate Period or the CY 11 period, then no later than March 1, 2009, the Parties shall amend this section 9(a) to include billing and payment provisions for: (1) the physically delivered Surplus Firm Power sale by PBL to Flathead; and (2) the power sale by Flathead to CFAC.

(b) **Billing and Payment When Monetary Benefits Provided**

(1) **Escrow Account**
BPA and Flathead shall establish an Escrow Account, in accordance with the laws governing Flathead, for MB Monthly Payments and any interruption payments pursuant to section 4(i). BPA shall make payments into the Escrow Account, but only Flathead shall have the ability to effect withdrawals from the Escrow Account for payment to CFAC.

(2) **Payments into the Escrow Account**
Within five Business Days after the end of each month, BPA will review CFAC's metered load measurements to determine if the Monthly Plant Load for the month is equal to or exceeds the Minimum Allocation.

Within eight Business Days following the end of the month, BPA shall transfer an amount equal to the MB Monthly Payment, and any interruption payments pursuant to section 4(i) above, into the Escrow Account.

(3) **Payments from the Escrow Account**
Within 12 business days following the end of the month, Flathead shall effect the transfer of all BPA monthly payment amounts received into the Escrow Account pursuant to this Agreement to CFAC.

(4) **Escrow Account Safeguard**
Flathead shall treat the Escrow Account in accordance with the terms of this Agreement and the agreement setting up the Escrow Account and not as property of Flathead. Flathead shall effect the release of such funds from the Escrow Account pursuant only to the escrow instructions consistent with this Agreement that BPA and Flathead shall develop and provide to the escrow agent. Except to the extent Flathead has failed to effect transfer of funds from the Escrow Account pursuant to the escrow instructions developed with BPA, Flathead shall not be liable under any circumstances for the funds deposited by BPA into the Escrow Account, and BPA and CFAC waive and release Flathead from any and all claims, liability or damages that could arise from any loss, payment or lack of payment of such funds in the Escrow Account.

(c) **General Terms**

(1) Limitation on Flathead's Payment Obligations
Notwithstanding anything in this Agreement to the contrary, Flathead shall have no obligation under any circumstances to pay to BPA any amounts under this Agreement, FPS rate schedule and GRSPs except for such amounts that Flathead has received from CFAC under this Agreement, and Flathead shall have no obligation under any circumstances to pay to CFAC any amounts under this

Agreement except for such amounts that BPA paid into the Escrow Account under this Agreement and that are available for transfer to CFAC.

(2) **Payment for Flathead's Administrative Costs**
Notwithstanding anything in this Agreement to the contrary, to the extent that Flathead incurs any expenses, fees, charges or costs of any kind not otherwise addressed in this Agreement, including but not limited to, attorneys fees, arising from Flathead's development of and performance under this Agreement, Flathead may bill CFAC and CFAC shall pay Flathead for any such costs in addition to the cost of power delivered from Flathead to CFAC. Amounts that CFAC pays Flathead pursuant to this paragraph 9(c)(2) shall not be treated as amounts Flathead has received from CFAC for purposes of determining the limit on Flathead's payment obligation to BPA under paragraph 9(c)(1) above.

10. NOTICES

Any notice required under this Agreement shall be in writing and shall be delivered: (a) in person; (b) by a nationally recognized delivery service; or (c) by United States Certified Mail. Notices are effective when received. Any Party may change its address for notices by giving notice of such change consistent with this section 10.

If to CFAC:

Columbia Falls Aluminum Company, LLC
40 Lake Bellevue, Suite 100
Bellevue, WA 98005
Attn: James D. Stromberg
Power Manager
Phone: 425-450-4010
FAX: 425-450-5569
E-Mail: Stromberg_cfac@att.net

If to PBL:

Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621
Attn: Scott K. Wilson – PT-5
Account Executive
Phone: 503-230-7638
FAX: 503-230-3681
E-Mail: skwilson@bpa.gov

If to Flathead:

Flathead Electric Cooperative, Inc.
2510 U.S. Highway 2 East
Kalispell, MT 59901
Attn: Ken A. Sugden
General Manager
Phone: 406-751-4401
FAX: 406-756-6617
E-Mail: fec@flatheadelectric.com

11. UNCONTROLLABLE FORCES

(a) **Uncontrollable Forces Provisions During Surplus Firm Power Sale**
If, during the FY 10-11 Rate Period, this Agreement operates as a physical Surplus Firm Power Sale, then the following provisions shall apply; *provided however,* that UBA determinations pursuant to section 7 and acquisitions of UBA pursuant to section 8 shall not be subject to Uncontrollable Forces under this section 11(a).

PBL shall not be in breach of its obligation to provide Surplus Firm Power to Flathead and Flathead shall not be in breach of its obligation to purchase Surplus Firm Power to the extent the failure to fulfill that obligation is due to an Uncontrollable Force. Similarly, Flathead shall not be in breach of its obligation to provide Surplus Firm Power to CFAC and CFAC shall not be in breach of its obligation to purchase Surplus Firm Power to the extent the failure to fulfill that obligation is due to an Uncontrollable Force. “Uncontrollable Force” means an event beyond the reasonable control of, and without the fault or negligence of, the Party claiming the Uncontrollable Force that prevents that Party from performing its obligations under this

Agreement and which, by exercise of that Party's reasonable diligence and foresight, such Party could not be expected to avoid and was unable to avoid. Uncontrollable Forces include, but are not limited to:

(1) any unplanned curtailment or interruption for any reason of firm transmission used to deliver Surplus Firm Power to CFAC's facilities, including but not limited to unplanned maintenance outages;

(2) any unplanned curtailment or interruption, failure or imminent failure of CFAC's production or transmission facilities, including but not limited to unplanned maintenance outages;

(3) any planned transmission or distribution outage that affects either CFAC or PBL which was provided by a third-party transmission or distribution owner, or by a transmission provider, including TBL, that is functionally separated from the generation provider in conformance with Federal Energy Regulatory Commission (FERC) Orders 888 and 889 or its successors;

(4) strikes or work stoppage, including the threat of imminent strikes or work stoppage; *provided, however*, that nothing contained in this provision shall be construed to require any Party to settle any strike or labor dispute in which it may be involved.

(5) floods, earthquakes, or other natural disasters; and

(6) orders or injunctions issued by any court having competent subject matter jurisdiction, or any order of an administrative officer which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court of competent subject matter jurisdiction.

Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic hardship of any Party shall not constitute an Uncontrollable Force. The Party claiming the Uncontrollable Force shall notify the other Parties as soon as practicable of that Party's inability to meet its obligations under this Agreement due to an Uncontrollable Force. The Party claiming the Uncontrollable Force shall notify any control area involved in the scheduling of a transaction which may be curtailed due to an Uncontrollable Force.

All Parties shall be excused from their respective obligations, other than from payment obligations incurred prior to the Uncontrollable Force, without liability to the other, for the duration of the Uncontrollable Force and the period reasonably required for the Party claiming the Uncontrollable Force, using due diligence, to restore its operations to conditions existing prior to the occurrence of the Uncontrollable Force.

(b) **Uncontrollable Forces Provisions During Periods When Monetary Benefit is Provided**
During periods when the Surplus Firm Power sale is monetized, CFAC understands and agrees that there are no events that will be considered Uncontrollable Forces under this Agreement.

12. GOVERNING LAW AND DISPUTE RESOLUTION

(a) This Agreement shall be interpreted consistent with and governed by Federal law. Disputes arising out of this Agreement that are not otherwise subject to the exclusive jurisdiction of the United States Court of Appeals for the Ninth Circuit are subject to the Contract Disputes Act, 41 USC 601, et seq.

(b) If a dispute arises under any provision of this Agreement, the Parties shall, within 14 business days following the initiation of a dispute, make a good faith effort to negotiate a resolution of such dispute before initiating the mediation provisions in section 12(c) below.

(c) If the Parties are unable to agree following negotiation pursuant to section 12(b) above, then either Party may request, in writing, to mediate the dispute. The Parties shall seek to reach agreement upon a mediator. In the event that they are unable to agree, then a mediator shall be selected by U.S. Arbitration and Mediation of Oregon. The Parties shall have 30 days from the date a Party initiated mediation to reach agreement before initiating litigation. BPA and CFAC shall each pay one half of the expenses of any mediation between or among the Parties.

(d) During a contract dispute or contract issue between or among Parties arising out of this Agreement, the Parties shall continue performance under this Agreement pending resolution of the dispute, unless to do so would be impossible or impractical. The Parties reserve the right to seek judicial resolution of any dispute arising out of this Agreement.

13. STATUTORY PROVISIONS

(a) **Priority of Pacific Northwest Customers**
The provisions of sections 9(c) and (d) of the Northwest Power Act and the provisions of P.L. 88-552 as amended by the Northwest Power Act are incorporated into this Agreement by reference. Flathead, together with other customers in the Region, shall have priority to BPA power, consistent with such provisions.

(b) **Limitation on Resale**
Flathead shall not resell Surplus Firm Power, as defined in this Agreement, to any entity except CFAC.

(c) **BPA Appropriations Refinancing Act**
The BPA Refinancing Section of the Omnibus Consolidated Rescissions and Appropriations Act of 1996 (The BPA Refinancing Act), P.L. No. 104-134, 110

Stat. 1321, 1350, is incorporated by reference and is a material term of this Agreement.

14. STANDARD PROVISIONS

(a) **Amendments**
No oral or written amendment, rescission, waiver, modification, or other change of this Agreement shall be of any force or effect unless set forth in a written instrument signed by authorized representatives of each Party.

(b) **Assignment**
CFAC may assign this Agreement upon 90 days prior written notice, but only to a successor-in-interest that has acquired ownership, through purchase or merger, of CFAC's facilities that are served, in whole or in part, with power or Monetary Benefits provided under this Agreement, and then only if such assignee expressly agrees in writing to be bound by the terms of this Agreement. In the event of such assignment, BPA will apply its then current credit policies to determine whether it will require security or assurances from the assignee to secure performance of assignee's obligations under this Agreement. Monetary Benefits under this Agreement are not transferable for use at other aluminum smelters. Such Monetary Benefits shall only be available for eligible production facilities referred to in Exhibit B of this Agreement, subject to any limitations specifically established in Exhibit B.

(c) **Information Exchange and Confidentiality**
The Parties shall provide each other with any information that is reasonably required, and requested by any Party in writing, to operate under and administer this Agreement, including load forecasts for planning purposes, information needed to resolve billing disputes, scheduling, and metering information reasonably necessary to prepare power bills that is not otherwise available to the requesting Party. Such information shall be provided in a timely manner. Information may be exchanged by any means agreed to by the Parties. If such information is subject to a privilege of confidentiality, a confidentiality agreement or statutory restriction under state or Federal law on its disclosure by a Party to this Agreement, then that Party shall endeavor to obtain whatever consents, releases, or agreements are necessary from the person holding the privilege to provide such information while asserting the confidentiality over the information. Information provided to BPA which is subject to a privilege of confidentiality or nondisclosure shall be clearly marked as such and BPA shall not disclose such information without obtaining the consent of the person or Party asserting the privilege, consistent with BPA's obligation under the Freedom of Information Act. BPA may use such information as necessary to provide service or timely bill for service under this Agreement. BPA shall only disclose information received under this provision to BPA employees who need the information for purposes of this Agreement.

(d) **Entire Agreement**
This Agreement, including all provisions, exhibits incorporated as part of this Agreement, and documents incorporated by reference, constitutes the entire agreement among the Parties. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement.

(e) **Exhibits**
The exhibits listed in the table of contents are incorporated into this Agreement by reference. The exhibits may only be revised upon mutual agreement among the Parties unless otherwise specified in the exhibits. The body of this Agreement shall prevail over the exhibits to this Agreement in the event of a conflict.

(f) **No Third-Party Beneficiaries**
This Agreement is made and entered into for the sole protection and legal benefit of the Parties, and no other person shall be a direct or indirect legal beneficiary of, or have any direct or indirect cause of action or claim in connection with this Agreement.

(g) **Waivers**
Any waiver at any time by any Party to this Agreement of its rights with respect to any default or any other matter arising in connection with this Agreement shall not be considered a waiver with respect to any subsequent default or matter.

(h) **BPA Policies**
Any reference in this Agreement to BPA policies, including without limitation BPA's New Large Single Load Policy and the 5(b)/9(c) Policy, and any revisions thereto, does not constitute agreement by CFAC or Flathead to such policy, nor shall it be construed to be a waiver of the right of CFAC or Flathead to seek judicial review of any such policy.

(i) **Severability**
If any term of this Agreement is found to be invalid by a court of competent jurisdiction then such term shall remain in force to the maximum extent permitted by law. All other terms shall remain in force unless that term is determined not to be severable from all other provisions of this Agreement by such court.

(j) **Hold Harmless**
BPA and CFAC assume all liability for injury or damage to persons or property arising from the act or negligence of its own employees, agents, members of governing bodies, or contractors. BPA and CFAC shall indemnify and hold the other Parties harmless from any liability arising from such act or negligence.

15. LIMITATION OF LIABILITY OF FLATHEAD AND HOLD HARMLESS

BPA and CFAC agree to and hereby do waive any suit, claim, demand or cause of action of any kind in law and equity which they may have or may assert against Flathead arising out of this Agreement, except to enforce Flathead's obligations pursuant to this Agreement (i) to effect transfer of Escrow Account funds pursuant to section 9(b) of this Agreement, and (ii) to pay such amounts received from CFAC to BPA in the amount of payments received by Flathead from CFAC pursuant to section 9(a) of this Agreement as may be amended pursuant to section 9(a) of this Agreement.

In no event or any circumstance shall Flathead be liable for special punitive, indirect, incidental or consequential losses or damages of any kind whatsoever (including but not limited to lost profits), even if Flathead has been advised of the likelihood of such loss or damage and regardless of the form of action.

Furthermore, BPA and CFAC agree to share equally any payment necessary to indemnify, hold harmless and reimburse Flathead for damages and/or any reasonable costs, other than Flathead's implementation and administrative costs billable to CFAC under section 9 of this Agreement, including, but not limited to, reasonable attorney fees, incurred by Flathead as a direct or indirect result of its participation in this Agreement.

BPA's and CFAC's agreement to indemnify and hold harmless Flathead pursuant to this section 15 shall survive the termination of this Agreement until extinguished by any applicable statue of limitations.

16. TERMINATION

(a) BPA may terminate this Agreement on 30 days written notice to the other Parties in the event the Ninth Circuit Court of Appeals or other court of competent jurisdiction issues a final, unappealable order preventing or prohibiting BPA from recovering under the Slice Agreements or its Slice rate schedules that portion of BPA's cost of service associated with this Agreement allocated by BPA to such Slice Agreements or Slice rate schedules. BPA shall diligently litigate any action challenging its ability to assess such costs. Neither CFAC nor Flathead shall be entitled to any damages for such termination and hereby expressly waives any right to seek such damages.

(b) If, pursuant to section 5(b) above, BPA provides written notice to convert the payment of Monetary Benefit to a physical Surplus Firm Power Sale during the CY 2010-2011 period or the CY 2011period, then CFAC may terminate this Agreement by providing written notice to Flathead and BPA no later than November 1, 2008. The effective date of any such termination shall be 2400 hours on the September 30 immediately preceding the effective date of such conversion . In this event, the Demand Entitlement becomes an UBA as of the effective date specified in this section 16(b), and shall be offered to Other DSIs pursuant to section 7(b)(4) above.

(c) In the event the Ninth Circuit Court of Appeals or other court of competent jurisdiction issues a final order that declares or renders this Agreement void or otherwise unenforceable, no Party shall be entitled to any damages or restitution of any nature, in law or equity, from any other Party, and each Party hereby expressly waives any right to seek such damages.

(d) Flathead may terminate its obligations under this Agreement upon 30 days written notice to the other Parties if there is an Event of Default by CFAC. An Event of Default shall mean the failure of CFAC to pay when due the reimbursements owed by CFAC to Flathead under sections 9(c)(2), 12(c), 14(j) and/or 15 if payment is not remedied within 30 Business Days after written notice. In the event of such termination by Flathead, BPA and CFAC will establish a mutually agreeable alternative means to effectuate the payments and the acquisition of BPA power by CFAC provided for in this Agreement.

17. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom they sign.

COLUMBIA FALLS ALUMINUM COMPANY, LLC

By **/S/ STEPHEN J. KNIGHT**

Name **Stephen J. Knight**
(Print/Type)

Title **Vice President**

Date **June 12, 2006**

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By **/S/ SCOTT K. WILSON**
Account Executive

Name Scott K. Wilson
(Print/Type)

Date **June 9, 2006**

FLATHEAD ELECTRIC COOPERATIVE, INC.

By **/S/ KENNETH A. SUGDEN**

Name **Kenneth A. Sugden**
(Print/Type)

Title **General Manager**

Date **June 14, 2006**

Exhibit A
SURPLUS FIRM POWER RATE

If BPA chooses to exercise its option, pursuant to section 5(b) of the body of this Agreement, to sell physically delivered Surplus Firm Power under this Agreement during the FY 10-11 Rate Period, then BPA shall unilaterally revise this Exhibit A, effective on October 1, 2009, to include the specific rates and charges that will apply to the physically delivered Surplus Firm Power sale. The cost to BPA to provide such physically delivered Surplus Firm Power will not exceed the cost caps as described in the Administrator's ROD.

Exhibit B
ADDITIONAL PRODUCTS, SERVICES, AND SPECIAL PROVISIONS

1. DESCRIPTION OF CFAC's PRODUCTION FACILITIES, STATION SERVICE REQUIREMENTS, AND METERING EQUIPMENT

Production Facilities: are CFAC's aluminum smelting and other facilities served from the Government's Conkelley Substation, where the 13.8 or 230 kilovolt (kV) facilities of BPA and CFAC are connected.

In addition to the production facilities identified above, CFAC's Total Plant Load may include, at CFAC's sole option, up to six (6) MW of service to the Evergreen Aluminum's (Evergreen) facility served from the Government's Alcoa Substation, where the 13.8 kV facilities of BPA and Evergreen are connected. When establishing CFAC's Total Plant Load the Evergreen portion shall be limited to the lesser of actual energy usage or 6 MW per hour.

Metering Equipment: used to measure energy usage of the CFAC facility and the Evergreen facility located in the Government's Conkelley Substation and Alcoa Substation in the 13.8 kV circuits over which such electric power and energy flows.

CFAC agrees to allow PBL access to all hourly load measurements of its Production Facilities necessary to administer this Agreement.

2. REVISIONS

This Exhibit B shall be revised upon mutual agreement of the Parties to reflect any new products, services, and special provisions that may be added during the term of this Agreement.

Exhibit C
BPA POWER BUSINESS LINE SCHEDULING PROVISIONS

1. PURPOSE OF THIS EXHIBIT

Unless otherwise specified in this Exhibit C, all transactions shall be scheduled in accordance with the Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Council (NERC). The purpose of this exhibit is to identify power scheduling requirements and coordination procedures necessary for the delivery of electric power products bought or sold under this Agreement. All provisions apply equally to all BPAP Counter Parties (as defined in section 2 below) and their authorized scheduling agents. Transmission scheduling arrangements are provided under separate agreements/provisions with the designated transmission provider.

2. DEFINITIONS

(a) **After the Fact**: The process of reconciling all transactions, Schedules, and accounts after they have occurred.

(b) **APOD**: Alternate Point Of Delivery. Any point other than the POD specified in a Confirmation Agreement or other contract to which this Exhibit C applies.

(c) **BPAP**: Bonneville Power Administration Power Business Line.

(d) **BPAP Counter Party**: A PSE (Purchasing Selling Entity, as defined by NERC) that has contracted to purchase from BPAP or sell to BPAP electric power products.

(e) **COB**: California-Oregon Border or COI (California-Oregon Intertie). Consists of the Pacific AC Intertie (PACI or Malin) and 3rd AC Intertie (3A or Captain Jack) transmission lines to California. N to S indicates that the energy is flowing on the transmission path North to South. S to N indicates energy is flowing on the transmission path South to North.

(f) **NOB**: Nevada-Oregon Border. Consists of the Pacific DC Intertie (PDCI or Celilo) transmission line to California. N to S indicates that the energy is flowing on the transmission path North to South. S to N indicates energy is flowing on the transmission path South to North.

(g) **POD**: Point of Delivery, as defined by NERC.

(h) **Preschedule Day**: Preschedule Day is in accordance with WECC practice and variations are identified in the WECC calendar to allow for Holidays, WECC meetings, etc.

(i) **Prescheduling**: The process (verbally and in writing) of establishing and balancing (checking out) schedules on the Preschedule Day.

(j) **Real-Time Scheduling**: Any new or modified Transaction that occurs after prescheduling is completed.

(k) **Schedule**: The planned Transaction approved and accepted by all counterparties and Control Areas involved in the Transaction.

3. COORDINATION: GENERAL, CONTROL AREA, PRESCHEDULE, REAL-TIME, AND AFTER-THE-FACT REQUIREMENTS

(a) **General Requirements**

(1) BPAP shall have the right to revise and replace this Exhibit C: (1) in the event that scheduling procedures are changed due to agreement among scheduling parties in the WECC; (2) to comply with rules or orders issued by the Federal Energy Regulatory Commission (FERC) or NERC, or (3) to implement changes reasonably necessary for BPAP to administer its power scheduling function in a more efficient manner.

(2) BPAP and each BPAP Counter Party must have necessary staff available during both parties' Prescheduling, Real-Time Scheduling, and After the Fact check out processes, including the completion of the NERC Etag.

(3) All transactions shall be stated in the Pacific Prevailing Time (PT), beginning with the 0100 hour ending.

(4) BPAP and each BPAP Counter Party shall notify each other of changes to telephone or fax numbers of key personnel (for Prescheduling, Real-Time Scheduling, After the Fact, or scheduling agents, etc.).

(b) **Prescheduling Requirements**

(1) **Information Required For Any Preschedule**

(A) When the NERC Tag is prepared, the BPAP Counter Party purchasing from BPAP shall use commercially reasonable efforts to ensure the BPAP Confirmation Agreement contract number is included within the generation/load segment, in the XML "Contract Number" element of the Etag.

(B) Transactions to or from COB must identify the use of either Malin or Captain Jack.

(2) **Preschedule Coordination**
Final hourly Schedules must be submitted by each BPAP Counter Party to BPAP for the next day(s) transactions by 1100 PT of each Preschedule Day, unless otherwise agreed. After 1100 PT Preschedules can be accepted if mutually agreed to by BPAP and the BPAP Counter Party, and the Preschedules are accepted by the transmission provider(s).

(c) **Real-Time Scheduling Requirements**

(1) BPAP Counter Parties may not make real-time changes to the schedules unless such changes are allowed under specific Confirmation Agreements or other contracts to which this Exhibit C applies, and by mutual agreement.

(2) If real-time changes to the schedule become necessary and are allowable as described in section 3(c)(1) above, the requesting BPAP Counter Party must submit requests for such changes no later than specified in the contract or BPAP Confirmation Agreement. Emergency schedule changes (including mid-hour changes) will be handled in accordance with WECC procedures.

(3) Multi-hour changes to the schedule shall specify an "hour beginning" and an "hour ending" and shall not be stated as "until further notice."

(d) **After the Fact Reconciliation Requirements**
Each BPAP Counter Party agrees to reconcile all transactions, Schedules, and accounts following the end of each month (within the first 10 calendar days of the next month).

Exhibit D
EXAMPLES

I. EXAMPLES OF THE CALCULATION OF MONETARY BENEFIT PAYMENTS

Following are examples of the calculation of Monetary Benefit payments pursuant to section 6 of the body of this Agreement.

Example No. 1: Calculation of MB Rate, Maximum MB Monthly Payment, and MB Monthly Payment.

Demand Entitlement	250	aMW
Hours in the Month Equals	744	

Difference Between Forecast Market Price and Equvalent PF	MB Rate	Maximum MB Payment	Minimum Load (aMW) to Receive Maximum MB Monthly Payment
$26.00	$24.00	$2,232,000	125.0000
$25.00	$24.00	$2,232,000	125.0000
$24.00	$24.00	$2,232,000	125.0000
$23.00	$24.00	$2,232,000	130.4348
$22.00	$24.00	$2,232,000	136.3636
$21.00	$24.00	$2,232,000	142.8571
$20.00	$24.00	$2,232,000	150.0000
$19.00	$19.00	$2,232,000	157.8947
$18.00	$18.00	$2,232,000	166.6667
$17.00	$17.00	$2,232,000	176.4706
$16.00	$16.00	$2,232,000	187.5000
$15.00	$15.00	$2,232,000	200.0000
$14.00	$14.00	$2,232,000	214.2857
$13.00	$13.00	$2,232,000	230.7692
$12.00	$12.00	$2,232,000	250.0000
$11.00	$11.00	$2,046,000	250.0000
$10.00	$10.00	$1,860,000	250.0000
$9.00	$9.00	$1,674,000	250.0000
$8.00	$8.00	$1,488,000	250.0000
$7.00	$7.00	$1,302,000	250.0000
$6.00	$6.00	$1,116,000	250.0000
$5.00	$5.00	$930,000	250.0000
$4.00	$4.00	$744,000	250.0000
$3.00	$3.00	$558,000	250.0000
$2.00	$2.00	$372,000	250.0000
$1.00	$1.00	$186,000	250.0000
$0.00	$0.00	$0	0.0000

Example No. 2: Difference between Forecast Market Price and Equivalent PF exceeds $24/MWh and the DSI's operation varies from less than its Minimum Allocation to its Maximum Allocation.

Forecast of Maximum MB Monthly Payment for CY

Equivalent PF subject to same adjustments established for the PF rate.

CY MB Monthly Payments, Demand Entitlement Equals 250 MW

In this example the DSI is entitled to the Maximum MB Monthly Payment each month that the actual monthly load equals or exceeds the Minimum Allocation. January through May monthly loads were less than the Minimum Allocation Requirement, and the MB Monthly Payments equal zero.

Example No. 3: Difference between Forecast Market Price and Equivalent PF equals $18/MWh and the DSI's operation varies from less than its Minimum Allocation to its Maximum Allocation

Forecast of Maximum MB Monthly Payment for CY

Equivalent PF subject to same adjustments established for the PF rate.

CY MB Monthly Payments, Demand Entitlement Equals 250 MW

In this example the DSI is entitled to the Maximum MB Monthly Payment only September. January thru May MB Monthly Payments equal zero because the DSI failed to meet the Minimum Allocation requirement. For the remaining months an MB Monthly Payment equal to the actual monthly load multiplied by the MB Rate ($18.00/MWh) was paid.

Example No. 4: Difference between Forecast Market Price and Equivalent PF equals $8/MWh and the DSI's operation varies from less than its Minimum Allocation to its Maximum Allocation.

Forecast of Maximum MB Monthly Payment for CY

Equivalent PF subject to same adjustments established for the PF rate.

CY MB Monthly Payments, Demand Entitlement Equals 250 MW

In this example, January through May the MB Monthly Payment equals zero because the DSI failed to meet the Minimum Allocation requirement. In the remaining months the MB Monthly Payment equals actual monthly load multiplied by the MB Rate ($8.00/MWh).

Example No. 5: Equivalent PF is greater than the Forecast Market Price and the DSI's operation varies from less than its Minimum Allocation to its Maximum Allocation

Forecast of Maximum MB Monthly Payment for CY

Equivalent PF subject to same adjustments established for the PF rate.

CY MB Monthly Payments, Demand Entitlement Equals 250 MW

In this example the Forecast Market Price is less than the Equivalent PF so there are no MB Monthly Payments made to the DSI.

II. EXAMPLES OF THE DETERMINATION OF UNUSED BENEFIT AMOUNTS

Following are examples of the determination of Unused Benefit Amounts pursuant to section 7 of the body of this Agreement.

Example No. 1: DSI's operation without any UBA made available at the end of the 12 month period. Maximum Allocation equals 250 aMW and the MB Rate equals $18/MWh.

No UBA is made available at the end of this 12month period because the DSI received a Maximum MB Monthly Payment in April but one more month without accessing the Maximum MB Monthly Payment will result in UBA; up to 6 percent of this DSI Maximum Allocation may be made available to the Other DSIs.

Example No. 2: DSI's operation with UBA resulting at the end of the 12-month period. Maximum Allocation/Demand Entitlement equals 250 aMW and the MB Rate equals $18/MWh.

In this example, the Maximum MB Monthly Payment was not accessed any month over the past 12 months. The DSI's Maximum Allocation times the highest percentage accessed (93.75%) over the pass 12 months rounded to the nearest aMW establishes its new Maximum Allocation (250 aMW * 0.9375 = 234.375 rounded to 234 aMW). UBA that will be made available to the Other DSIs is 250 aMW minus 234 aMW, 16 aMW.

Example No. 3: DSI's operation with UBA resulting at the end of the 12-month period. Maximum Allocation/Demand Entitlement equals 250 aMW and the MB Rate equals $12/MWh.

In this example, the Maximum MB Monthly Payment was not accessed any month over the past 12 months. The DSI's Maximum Allocation times the highest percentage accessed (62.50%) over the pass 12 months rounded to the nearest aMW establishes its new Maximum Allocation (250 aMW * 0.62.50 = 156.25 rounded to 156 aMW). UBA that will now be made available to the Other DSIs is 250 aMW minus 156 aMW, 94 aMW.

III. EXAMPLES OF THE ACQUISITION OF UNUSED BENEFIT AMOUNTS

Following are examples of the acquisition of Unused Benefit Amounts pursuant to section 8 of the body of this Agreement.

Example No. 1: Maximum Allocation increases of two DSI who both increased operation to acquire nearly all available UBA (94 aMW).

In this example DSI-A was allocated 50 aMW and DSI-B was allocated 39 aMW. The new Demand Entitlement for DSI-A is 190 aMW and 139 aMW for DSI-B. The remaining 5 aMW of UBA was never acquired and after September was not available to any DSIs.

Example No. 2: Same as Example #1 except DSI-A has a contractually limited Maximum Allocation of 171 aMW.

In this example DSI-A's Demand Entitlement was limited to 171 aMW. DSI-A was allocated 31 aMW and DSI-B was allocated its 39 aMW of UBA. Available UBA was 24 aMW through September but because none was acquired during this period it was no longer available to any DSIs afterward.

Example No. 3: Maximum Allocation of two DSIs increased over 2-month period with full amount of UBA (94 aMW) allocated.

In this example DSI-B increased its load in April sufficient to acquire 45 aMW of the available UBA, resulting in its Maximum Allocation increasing from 100 aMW to 145 aMW beginning with May. Both DSIs increased load sufficiently for the remaining UBA to be allocated during May, increasing DSI-A's Maximum Allocation to 164 aMW and DSI-B's Maximum Allocation to 170 aMW.

Exhibit E
MAXIMUM ALLOCATION, MINIMUM ALLOCATION, AND DEMAND ENTITLEMENT

1. MAXIMUM AND MINIMUM ALLOCATIONS

During periods when Monetary Benefit payments are provided pursuant to section 6 of the body of this Agreement, the Maximum Allocation, Minimum Allocation, and Monetary Benefit Limit amounts are as follows:

Maximum Allocation:	140 aMW
Minimum Allocation:	35 aMW
Monetary Benefit Limit:	$14 ,716,800/CY (Leap Year $40,320 greater.)

2. DEMAND ENTITLEMENT

During periods when this Agreement operates as a physical Surplus Firm Power sale pursuant to section 4 of the body of this Agreement, the Demand Entitlement shall be as follows:

Demand Entitlement:	140 MW

3. **REVISIONS**

BPA shall unilaterally revise this Exhibit E to reflect changes to Maximum Allocation, Minimum Allocation, Monetary Benefit Limit, and/or Demand Entitlement.

Exhibit F
DETERMINATION OF FORECAST MARKET PRICE AND EQUIVALENT PF

1. DETERMINATION OF FORECAST MARKET PRICE

Prior to the beginning of each Contract Year, the following provisions shall be used to determine the Forecast Market Price.

(a) **Definitions**

(1) **“2007-2011 Agreements”** means the agreements between BPA and each PNW IOU that provide for among other things, the determination of the Forward Flat-Block Price Forecast for each year, 2007 through 2011.

(2) **“FBPF Exhibit”** means the exhibit titled “Determination of Forward Flat-Block Price Forecast For Contract Years 2007 through 2011, which is attached to each of the 2007-2011 Agreements.

(3) **"Forward Flat-Block Price Forecast"** or **"FBPF"** means the Forward Flat-Block Price Forecast developed from time to time under the 2007-2011 Agreements.

(4) **“Forward Price Data Agreement”** means BPA Contract No. 04PB-11534 among BPA and the PNW IOUs.

(5) **“PNW Investor-Owned Utility”** or **“PNW IOU”** means each of the following investor-owned utilities (and its investor-owned utility successors and assigns) that serves residential and small farm customers in the Pacific Northwest: Puget Sound Energy, Inc., PacifiCorp, Portland General Electric Company, Avista Corporation, Idaho Power Company, and NorthWestern Energy Division of NorthWestern Corporation.

(b) **Determination of Forecast Market Price**

(1) BPA has contracted with a qualified third party (QTP) pursuant to the FBPF Exhibit to determine the Forward Flat-Block Price Forecast for each Contract Year, 2007 through 2011.

(2) During four consecutive quarters prior to the beginning of each Contract Year, 2007 through 2011, the QTP surveys certain eligible data providers (EDPs) that have signed contracts in the form of Exhibit A to the Forward Price Data Agreement.

(3) The first quarterly survey for CY 2007 is conducted during Q1 of calendar year 2005 (January 2005-March 2005). The last quarterly survey for CY 2007 is conducted during Q4 of calendar year 2005 (October 2005-December 2005). The same procedure is followed for CY 2008 through 2011 but the quarters surveyed change to calendar

years 2006 through 2009, respectively. Each quarterly survey results in an FBPF for the upcoming CY. The average of the four quarterly FBPFs is the FBPF that is used to calculate benefits under the 2007-2011 Agreements.

(4) For the purpose of determining Monetary Benefit pursuant to section 6 of the body of this Agreement, the Forecast Market Price shall be equal to the FBPF established for Q4 of each calendar year for the upcoming CY. For example, the FBPF for Q4 of calendar year 2005 shall be the Forecast Market Price for CY 2007.

The Forecast Market Price for CY 2007 is $67.75/MWh.

2. DETERMINATION OF EQUIVALENT PF

Prior to the beginning of each CY, BPA will calculate the initial Equivalent PF for each such CY and, if applicable, for the Option Period.

(a) For Monetary Benefits not included in Option Benefits the Equivalent PF shall be equal to the actual cost, in $/MWh, to purchase 1 MW during every hour of the CY at the PF Rate (including but not limited to the effect of any adjustments, surcharges, dividends or true-ups) divided by the number of hours in the CY.

(b) For Monetary Benefits included in Option Benefits the Equivalent PF for the Option Period shall be the weighted average of the Equivalent PF for each CY included in whole or part within the Option Period calculated as follows: (i) For each CY within the Option Period, a CY Total Plant Load will be calculated by summing the monthly Total Plant Loads for each month of the CY that falls within the Option Period. For this calculation monthly Total Plant Load shall be limited to the Maximum Allocation, less UBA amounts not included in Option Benefits, and will be deemed equal to zero if the monthly Total Plant load is less than the Minimum Allocation. (ii) Each CY Total Plant Load for each CY from step i will then be multiplied by the Equivalent PF for the corresponding CY. (iii) The sum of the numbers calculated in step ii will then be divided by the sum of the CY Total Plant Loads from step i for the entire Option Period to derive the Equivalent PF for the Option Period. For purposes of this calculation, if the Option Period extends beyond CY 2009, BPA will deem the Equivalent PF Rate equal to a rate that results in an MB Rate, for periods beyond the CY 2009, equal to $24/MWh until BPA's initial proposal is published for the FY 10-11 Rate Period. When the initial proposal for FY 10-11 Rate Period is published the Equivalent PF used in this calculation for CY 2010 and CY 2011 will be established according to 2(c) below.

(c) Each time any adjustment, surcharge, dividend or true-up to the PF Rate is proposed by BPA in writing (which may be before the date such change will actually be applied to the PF Rate), BPA will adjust the Equivalent PF and the MB Rate and MB Monthly Payments for the remaining months of such CY or Option Period. Such adjustment will take into consideration the

Monetary Benefits provided to date and the PF Rate adjustment to provide an end-of-CY or end of Option Period total Monetary Benefit to which CFAC is entitled. If such recalculation indicates that BPA has paid CFAC more in Monetary Benefits than the amount to which CFAC is entitled, then BPA will reduce the MB Monthly Payments to CFAC over the next following three months (if full recovery of the amount is not possible in the 3-month period BPA may invoice CFAC for the remaining amount), by the amount needed to recover the overpayment. If adjustments, surcharges, and true-ups are established after the CY or Option Period ends, then BPA will calculate the final Equivalent PF rate for each such CY or Option Period, and adjustments to Monetary Benefit will be applied in the following CY.

(d) If, upon termination of this Agreement, a true-up or other adjustment following the end of the final CY results in a payment owed by CFAC to BPA, then BPA shall invoice CFAC for such payment within 90 days following the end of such final CY. Such payment shall be made by CFAC within 20 days following the receipt of such invoice. If, upon termination of this Agreement, a true-up or other adjustment following the end of the final CY results in a payment owed by BPA to CFAC, then BPA shall pay CFAC no later than 90 days following the end of such final CY.

3. REVISIONS

BPA shall have the unilateral right to revise this Exhibit F to reflect the Forecast Market Price and Equivalent PF for each CY after CY 2007 calculated pursuant to this Exhibit F. Any changes to the procedure used to determine Forecast Market Price or Equivalent PF may only be made upon mutual agreement of the Parties.

Attachment H

Contract No. 06PB-11694, Power Sale to Clallam PUD for Service at Port Townsend
(September 2006)

Contract No. 06PB-11694

AUTHENTICATED

SURPLUS FIRM POWER SALES AGREEMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

PUBLIC UTILITY DISTRICT NO. 1

OF CLALLAM COUNTY, WASHINGTON

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This SURPLUS FIRM POWER SALES AGREEMENT (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA), and PUBLIC UTILITY DISTRICT NO. 1 OF CLALLAM COUNTY, WASHINGTON (Clallam). Clallam is a public utility district organized under the laws of the State of Washington. BPA and Clallam are sometimes referred to in the singular as “Party” or in the plural as “Parties”.

RECITALS

The Administrator is authorized under the Northwest Power Act to sell surplus power. BPA projects it will have surplus power available for sale during the term of this Agreement.

BPA will sell and Clallam will purchase an amount of surplus power on a firm basis under this Agreement for resale by Clallam to Port Townsend Paper Corporation (Port Townsend) under a separate agreement.

BPA has administratively divided its organization into two business lines in order to functionally separate the administration and decision making activities of BPA's power business from the administrative and decision making activities of its transmission business. References in this Agreement to the Power Business Line (PBL) are solely for the purpose of establishing which BPA business line is responsible for the administration of this Agreement.

BPA and Clallam agree:

1. TERM

This Agreement shall become effective on October 1, 2006, and shall continue in effect through September 30, 2011, unless terminated earlier pursuant to section 14 below. All liabilities incurred hereunder shall be preserved until satisfied.

2. DEFINITIONS

Capitalized terms in this Agreement shall have the meanings defined below, in the exhibits or in context. All other capitalized terms and acronyms are defined in BPA's applicable Wholesale Power Rate Schedule(s), including the General Rate Schedule Provisions (GRSPs).

(a) "Contract Year" or "CY" means the period that begins each October 1 and which ends the following September 30. For instance, Contract Year 2007 begins October 1, 2006, and continues through September 30, 2007.

(b) "Northwest Power Act" means the Pacific Northwest Electric Power Planning and Conservation Act of 1980, P.O. 96-501.

(c) "Point of Measurement" means the Port Townsend Meter No. 2871 in Port Townsend's New Mill Substation, which is the point where Total Metered Load is measured.

(d) "Point of Receipt" means the points of interconnection on the transmission provider's transmission system where Surplus Firm Power shall be made available by PBL to Clallam.

(e) "Power Business Line" or "PBL" means that portion of the BPA organization or its successor that is responsible for the management and sale of BPA's Federal power.

(f) "Priority Firm Rate" means the Priority Firm Rate demand, energy, load variance and all other charges applicable to the purchase by Clallam of firm power from BPA under its PSC during each rate period during the term of this Agreement, including any and all Cost Recovery Adjustment Clauses (CRACs), NFB Adjustments, Emergency NFB Surcharges, Dividend Distribution Clauses (DDCs), and any other charges, surcharges, adjustments and rebates, but excluding the Low Density Discount and the Conservation Rate Credit.

(g) "Region" means the definition established for "Region" in the Northwest Power Act.

(h) "Surplus Firm Power" means electric power that PBL shall make available to Clallam under this Agreement.

(i) "Surplus Firm Power" means electric power that PBL shall make available to Clallam under this Agreement.

(j) "Total Metered Load" means the total amount of electric energy consumed during a given time period at Port Townsend's production facilities, located on Mill Road, Port Townsend, Washington, as measured at the Point of Measurement.

(k) "Transmission Business Line" or "TBL" means that portion of the BPA organization or its successor that is responsible for the management and sale of transmission service on the Federal Columbia River Transmission System (FCRTS).

3. SALE AND PURCHASE OF SURPLUS FIRM POWER AND RELATIONSHIP TO THE POWER SALES CONTRACT

(a) **Sale and Purchase of Surplus Firm Power**
BPA agrees to make available to Clallam at the Point of Receipt amounts of Surplus Firm Power, and Clallam agrees to purchase and pay for the amounts of Surplus Firm Power made available to Clallam at the Point of Receipt, all pursuant to the terms and conditions set forth in this Agreement.

(b) **Relationship to the Power Sales Contract**
Clallam also purchases power from BPA pursuant to Contract No. 00PB-12051, Full Service Power Sales Agreement (PSC), executed by the Parties on October 17, 2000, as it may be amended or replaced. If any provision of this Agreement conflicts with a specific provision in the PSC, as it may be amended or replaced, then for the purposes of this Agreement, this Agreement shall control.

4. APPLICABLE RATES

Purchases by Clallam under this Agreement are subject to the WP-07 Firm Power Products and Services (FPS) rate schedule or its successor and the General Rate Schedule Provisions.

Exhibit A, Surplus Firm Power Rate, identifies rates, and billing determinants applicable to purchases of Surplus Firm Power under this Agreement, and is incorporated by reference as if fully set forth in this Agreement.

5. POWER SALE PROVISIONS

All Surplus Firm Power provided by PBL under this Agreement is solely for service to Total Metered Load. Total Metered Load shall only be served with power purchased under this Agreement except for amounts of power that Clallam and BPA agree can be used to serve a portion of Total Metered Load in order to reduce the amount of Unauthorized Increase (UAI) charges that Clallam would otherwise be subject to for deliveries under this Agreement. The Surplus Firm Power provided under this Agreement is intended to support a corresponding wholesale power sale by Clallam to Port Townsend. Power amounts provided under this Agreement are not included in Clallam's Total Retail Load for any purpose under the PSC, including without limitation qualification for or the amount of benefits Clallam may receive under the Low Density Discount.

(a) **Demand**

The monthly megawatt (MW) amount that is measured during the hour of BPA's Generation System Peak establishes billing determinant for Clallam's Demand for Total Metered Load under this Agreement.

(b) **HLH and LLH Energy**

The monthly amounts of HLH and LLH energy, as measured at the Point of Measurement, establish Clallam's HLH and LLH Energy for service to Total Metered Load under this Agreement.

6. SCHEDULING

The Parties shall amend this Agreement as needed if any transmission tariff or regulatory agency requires or recommends changes that PBL decides to accept, which PBL determines require power scheduling provisions be made a part of this Agreement.

7. DELIVERY

(a) **Transmission Service for Contracted Power**

This Agreement does not provide transmission services for, or include the delivery of, Surplus Firm Power to Clallam. Clallam shall be responsible for arranging to have Port Townsend modify existing or execute one or more wheeling agreements with a transmission supplier for the delivery of Surplus Firm Power (Wheeling Agreement). The Parties agree to take such actions as may be necessary to facilitate the delivery of Surplus Firm Power consistent with the terms, notice, and the time limits contained in the Wheeling Agreements.

(b) **Liability for Delivery**

Clallam waives any claims against PBL arising under this Agreement for nondelivery of power to any points beyond the applicable Points of Receipt. PBL shall not be liable for any third-party claims related to the delivery of power after it leaves the Points of Receipt. In no event will either Party be liable under this Agreement to the other Party for damage that results from any sudden, unexpected, changed, or abnormal electrical condition occurring in or on any electric system, regardless of ownership.

(c) **Points of Receipt**

PBL shall make Surplus Firm Power available to Clallam under this Agreement at Points of Receipt solely for the purpose of scheduling transmission to points of delivery to Port Townsend Paper. Clallam shall have Port Townsend schedule, if scheduling is necessary, such Surplus Firm Power solely for service to Total Metered Load. PBL, for purposes of scheduling transmission for delivery under this Agreement, specified Points of Receipt in a written notice to Port Townsend on July 26, 2000.

If required by the Wheeling Agreement, PBL will provide capacity amounts for transmission under the Wheeling Agreement associated with the initial Points of Receipt that can be accepted as firm Points of Receipt under Port Townsend's Wheeling Agreement (provide however if the firm points of Receipt are not available, that all Points of Receipt on the Federal Columbia River Power System (FCRPS) would be considered nonfirm). The sum of capacity amounts shall not exceed the amount reasonably necessary for PBL to provide Surplus Firm Power under this Agreement. At any time PBL may request the use of nonfirm Points of Receipt to provide Surplus Firm Power to Clallam. Notwithstanding section 7(b) above, PBL shall reimburse Clallam for any additional costs incurred due to compliance with such request, if any such costs are passed through to Clallam from Port Townsend's Wheeling Agreement.

(d) **Transmission Losses**

PBL shall provide Clallam the losses for Surplus Firm Power between the Points of Receipt and Clallam's system for Surplus Firm Power, at no additional charge. Such losses will be provided at Points of Receipt as established under section 7©, and under the terms and conditions as defined in the transmission provider's tariff.

(e) **Clallam Network Transmission Agreement**

The Parties acknowledge that this Agreement is not intended to be and does not constitute a resource under Service Agreement no. 01TX-10410 (Network Transmission Agreement) by and between Clallam and TBL, and that notwithstanding anything in this Agreement to the contrary Clallam may not use its Network Transmission Agreement to deliver any power under this Agreement or from any other resource to Port Townsend's Total Metered Load.

8. MEASUREMENT

Clallam authorizes PBL to use metering data as PBL determines is necessary to plan, schedule, and bill for power. Clallam agrees to authorize TBL to provide Clallam's metering data directly to PBL subject to any restrictions imposed by the Federal Energy Regulatory Commission (FERC). All Points of Measurement are shown in Exhibit C, Points of Measurement. Clallam agrees to provide reasonable notice to PBL prior to changing control areas.

9. BILLING AND PAYMENT

(a) **Billing**
PBL shall bill Clallam monthly, consistent with applicable BPA rates, including the GRSPs and the provisions of this Agreement for the Surplus Firm Power provided to Clallam in the preceding month or months under this Agreement. PBL may send Clallam an estimated bill followed by a final bill. PBL shall send all bills on the bill's issue date either electronically or by mail, at Clallam's option. If electronic transmittal of the entire bill is not practical, PBL shall transmit a summary electronically, and send the entire bill by mail.

(b) **Payment**
Payment of all bills, whether estimated or final, must be received by BPA on the 20th day after the issue date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or Federal holiday, the Due Date is the next business day. If payment has been made on an estimated bill before receipt of a final bill for the same month, Clallam shall pay only the amount by which the final bill exceeds the payment made for the estimated bill. PBL shall provide Clallam the amounts by which an estimated bill exceeds a final bill through either a check or as a credit on the subsequent month's bill. After the Due Date, a late payment charge shall be applied each day to any unpaid balance. The late payment charge is calculated by dividing the Prime Rate for Large Banks as reported in the Wall Street Journal, plus 4 percent; by 365. The applicable Prime Rate for Large Banks shall be the rate reported on the first day of the month in which payment is received. Clallam shall pay by electronic funds transfer using BPA's established procedures, and may elect to have bills under this Agreement consolidated with those rendered under the PSC.

(c) **Disputed Bills**
In case of a billing dispute, Clallam shall note the disputed amount and pay its bill in full by the Due Date. Unpaid bills (including both disputed and undisputed amounts) are subject to late payment charges provided above. If Clallam is entitled to a refund of any portion of the disputed amount, then BPA shall make such refund with simple interest computed from the date of receipt of the disputed payment to the date the refund is made. The daily interest rate used to determine the interest is calculated by dividing the Prime Rate for Large Banks as reported in the Wall Street Journal; by 365. The applicable Prime Rate for Large Banks shall be the rate reported on the first day of the month in which payment is received by BPA.

(d) **Payments Hereunder Not Conditional on Payments by Port Townsend**
Payment of any bill under this Agreement by Clallam is not conditional on payment of any amount due by Port Townsend to Clallam for power provided by Clallam to meet Port Townsend.

10. UNCONTROLLABLE FORCES

PBL shall not be in breach of its obligation to provide Surplus Firm Power to Clallam and Clallam shall not be in breach of its obligation to purchase Surplus Firm Power to the extent the failure to fulfill that obligation is due to an Uncontrollable Force. "Uncontrollable Force" means an event beyond the reasonable control of, and without the fault or negligence of, the Party claiming the Uncontrollable Force that prevents that Party from performing its obligations under this Agreement and which, by exercise of that Party's reasonable diligence and foresight, such party could not be expected to avoid and was unable to avoid. Uncontrollable Forces include, but are not limited to:

(a) any unplanned curtailment or interruption for any reason of firm transmission used to deliver Surplus Firm Power to Clallam's facilities, including but not limited to unplanned maintenance outages;

(b) any unplanned curtailment or interruption, failure or imminent failure of Clallam's or Port Townsend's production or transmission facilities, including but not limited to unplanned maintenance outages;

(c) any planned transmission or distribution outage that affects either Clallam or PBL which was provided by a third-party transmission or distribution owner, or by a transmission provider, including TBL, that is functionally separated from the generation provider in conformance with Federal Energy Regulatory Commission (FERC) Orders 888 and 889 or its successors;

(d) strikes or work stoppage, including the threat of imminent strikes or work stoppage; *provided, however,* that nothing contained in this provision shall be construed to require any Party to settle any strike or labor dispute in which it may be involved.

(e) floods, earthquakes, or other natural disasters; and

(f) orders or injunctions issued by any court having competent subject matter jurisdiction, or any order of an administrative officer which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court of competent subject matter jurisdiction.

Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic hardship of any Party shall not constitute an Uncontrollable Force. The Party claiming the Uncontrollable Force shall notify the other Party as soon as practicable of that Party's inability to meet to meet its obligations under this Agreement due to an Uncontrollable Force. The Party claiming the Uncontrollable Force shall notify any control area involved in the scheduling of a transaction which may be curtailed due to an Uncontrollable Force.

Both Parties shall be excused from their respective obligations, other than from payment obligations incurred prior to the Uncontrollable Force, without liability to the other, for the duration of the Uncontrollable Force and the period reasonably required for the Party claiming the Uncontrollable Force, using due diligence, to restore its operations to conditions existing prior to the occurrence of the Uncontrollable Force.

11. NOTICES

Any notice required under this Agreement shall be in writing and shall be delivered: (a) in person; (b) by e-mail; (c) by United States Mail; (d) by a nationally recognized delivery service; or (e) by United States Certified Mail. Notices are effective when received. Any Party may change its address for notices by giving notice of such change consistent with this section 11.

If to Clallam:	If to PBL:
Public Utility District No. 1 of Clallam County, Washington P.O. Box 1090 Port Angeles, WA 98362-0212	Bonneville Power Administration
Attn: Fred Mitchell Telecommunications & Power Resources Manager Phones: 360-565-3235 FAX: 360-687-5139 E-Mail: fredm@clallampud.net	Attn: Charles W. Forman, Jr. – PSW- 6 Account Executive Phone: 503-230-3432 FAX: 503-230-3242 E-Mail: cformanjr@bpa.gov

12. GOVERNING LAW AND DISPUTE RESOLUTION

(a) This Agreement shall be interpreted consistent with and governed by Federal Law. Final actions subject to section 9(e) of the Northwest Power Act are not subject to binding arbitration and shall remain within the exclusive jurisdiction of the United States Ninth Circuit Court of Appeals. Any dispute regarding any rights of the Parties under any BPA policy, including the implementation of such policy, shall not be subject to arbitration under this Agreement. Clallam reserves the right to seek judicial resolution of any dispute arising under this Agreement that is not subject to arbitration under this section 12. For purposes of this section 12, BPA policy means any written document adopted by BPA as a final action in a decision record or record of decision that establishes a policy of general application, or makes a determination under an applicable statute. If either Party asserts that a dispute is excluded from arbitration under this section 12, either Party may apply to the Federal court having jurisdiction for an order determining whether such dispute is subject to arbitration under this section 12.

(b) Any contract dispute or contract issue between the Parties arising out of this Agreement, except for disputes that are excluded through section 12(a) above, shall be subject to binding arbitration. The Parties shall make a good faith effort to resolve such disputes before initiating arbitration proceedings. During arbitration, the Parties shall continue performance under this Agreement pending resolution of the dispute, unless to do so would be impossible or impracticable.

(c) Any arbitration shall take place in Portland, Oregon, unless the parties agree otherwise. The International Institute for Conflict Prevention and Resolution's arbitration procedures for commercial arbitration, Non-Administered Arbitration Rules (CPR Rules), shall be used for each dispute; **provided, however,** that: (1) the Parties shall have the discovery rights provided in the Federal Rules of Civil Procedure unless the Parties agree otherwise; and (2) for claims of $1 million or more, each arbitration shall be conducted by a panel of three neutral arbitrators. The Parties shall select the arbitrators from a list containing the names of 15 qualified individuals supplied by the International Institute for Conflict Prevention and Resolution. If the Parties cannot agree upon three arbitrators on the list within 20 business days, the Parties shall take turns striking names from the list of proposed arbitrators. The Parties shall take turns striking names from the list of proposed arbitrators. The Party initiating the arbitration shall take the first strike. This process shall be repeated until three arbitrators remain on the list, and those individuals shall be designated as the arbitrators. For disputes involving less than $1 million, a single neutral arbitrator shall be selected consistent with section 6 of the CPR Rules.

(d) Except for arbitration awards which declare the rights and duties of the Parties under this Agreement, the payment of monies shall be the exclusive remedy available in any arbitration proceeding. Under no circumstances shall specific performance be an available remedy against either Party. The arbitration award shall be final and binding on both Parties, except that either Party may seek judicial review based upon any of the grounds referred to in the Federal Arbitration Act, 9 U.S.C. §1-16 (1988). Judgment upon the award rendered by the arbitrators may be entered by any court having jurisdiction thereof.

(e) Each Party shall be responsible for its own costs of arbitration, including legal fees. The arbitrators may apportion all other costs of arbitration between the Parties in such manner as they deem reasonable taking into account the circumstances of the case, the conduct of the Parties during the proceeding, and the result of the arbitration.

13. STANDARD PROVISIONS

(a) **Amendments**
No oral or written amendment, rescission, waiver, modification, or other

change of this Agreement shall be of any force or effect unless set forth in a written instrument signed by authorized representatives of each Party.

(b) **Assignment**
This Agreement is binding on any successors and assigns of the Parties. BPA may assign this Agreement to another Federal agency to which BPA's statutory duties have been transferred. Neither Party may otherwise transfer or assign this Agreement, in whole or in part, without the other Party's written consent. Such consent shall not be unreasonably withheld. BPA shall consider any request for assignment consistent with applicable BPA statutes. Clallam may not transfer or assign this Agreement to any of its retail customers.

(c) **Information Exchange and Confidentiality**
The Parties shall provide each other with any information that is reasonably required, and requested by either Party in writing, to operate under and administer this Agreement, including load forecasts for planning purposes, information needed to resolve billing disputes, scheduling and metering information reasonably necessary to prepare power bills that is not otherwise available to the requesting Party. Such information shall be provided in a timely manner. Information may be exchanged by any means agreed to by the Parties. If such information is subject to a privilege of confidentiality, a confidentiality agreement or statutory restriction under state or Federal law on its disclosure by a Party to this Agreement, then that party shall endeavor to obtain whatever consents, releases, or agreements are necessary from the person holding the privilege to provide such information while asserting the confidentiality over the information. Information provided to BPA which is subject to a privilege of confidentiality or nondisclosure shall be clearly marked as such and BPA shall not disclose such information without obtaining the consent of the person or Party asserting the privilege, consistent with BPA's obligation under the Freedom of Information Act. BPA may use such information as necessary to provide service or timely bill for service under this Agreement. BPA shall only disclose information received under this provision to BPA employees who need the information for purposes of this Agreement.

(d) **Entire Agreement**
This Agreement, including all provisions, exhibits incorporated as part of this Agreement, and documents incorporated by reference, constitutes the entire agreement between the Parties. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement.

(e) **Exhibits**
The exhibits listed in the table of contents are incorporated into this Agreement by reference. The exhibits may only be revised upon mutual agreement between the Parties unless otherwise specified in the exhibits. The body of this Agreement shall prevail over the exhibits to this Agreement

in the event of a conflict.

(f) **Third-Party Beneficiaries**
Port Townsend is an intended third-party beneficiary of BPA's obligation under the terms of this Agreement to provide Surplus Firm Power to Clallam, and Clallam's obligation under the terms of this Agreement to pay for such power. Except as provided in the preceding sentence, this Agreement is made and entered into for the sole protection and legal benefit of the Parties, and no other person shall be a direct or indirect legal beneficiary of, or have any direct or indirect cause of action or claim in connection with this Agreement

(g) **Waivers**
Any waiver at any time by either Party to this Agreement of its rights with respect to any default or any other matter arising in connection with this Agreement shall not be considered a waiver with respect to any subsequent default or matter.

(h) **BPA Policies**
Any reference in this Agreement to BPA policies, including without limitation BPA's NLSL Policy and the 5(b)/9(c) Policy, and any revisions thereto, does not constitute agreement by Clallam to such policy, nor shall it be construed to be a waiver of the right of Clallam to seek judicial review of any such policy.

(i) **Severability**
If any term of this Agreement is found to be invalid by a court of competent jurisdiction then such term shall remain in force to the maximum extent permitted by law. All other terms shall remain in force unless such term is determined to be material to this Agreement, or is not severable from all other provisions of this Agreement by such court.

(j) **Hold Harmless**
Each Party assumes all liability for injury or damage to persons or property arising from the act or negligence of its own employees, agents, members of governing bodies, or contractors. Each Party shall indemnify and hold the other Party harmless from any liability arising from such act or negligence.

(k) **BPA Appropriations Refinancing Act**
The Parties agree that the BPA Refinancing Section of the omnibus Consolidated Recisions and Appropriations Act of 1996 (The BPA Refinancing Act), P.L. No. 104-134, 110 Stat. 1321, 1350, as stated in the United States Code on the date this Agreement is signed by the Parties, is incorporated by reference and is a material term of this Agreement. The Parties agree that this provision and the incorporated text shall be included in subsequent agreements between the Parties, as a material term through at least September 30, 2011.

14. TERMINATION

(a) BPA may terminate this Agreement on 30 days written notice to Clallam in the event the Ninth Circuit Court of Appeals or other court of competent jurisdiction issues a final, unappealable order preventing or prohibiting BPA from recovering under the Slice Agreements or its Slice rate schedules that portion of BPA's cost of service associated with this Agreement allocated by BPA to such Slice Agreements or Slice rate schedules. BPA shall diligently litigate any action challenging its ability to assess such costs. Clallam shall not be entitled to any damages for such termination and Clallam hereby expressly waives any right to seek such damages.

(b) In the event the ninth Circuit Court of Appeals or other court of competent jurisdiction issues a final, unappealable order that declares or renders this Agreement void or otherwise unenforceable, Clallam shall not be entitled to any damages of any nature, in law or equity, from BPA. Clallam hereby expressly waives any right to seek such damages from BPA.

(c) PBL may terminate this Agreement if Clallam fails to pay any bill due to BPA within 5 business days after its Due Date.

(d) PBL may terminate or suspend this Agreement on 5 days written notice to Clallam if Port Townsend fails to pay any bill due to BPA within 5 business days after its Due Date.

15. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom they sign.

PUBLIC UTILITY DISTIRCT NO. 1 OF CLALLAM COUNTY, WASHINGTON

By **/S/ MICHAEL MCINNES**

Name Michael McInnes
(Print/Type)

Title Interim General Manager

Date **September 13, 2006**

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By **/S/ CHUCK FORMAN, JR.**
Account Executive

Name Charles W. Forman, Jr.
(Print/Type)

Date **August 22, 2006**

(W:PSW\PM\AE_Forman\CL_Clallam\Surplus Firm PSC\CL_06PB-11694_20060821_Final.doc)8/21/06

Exhibit A
SURPLUS FIRM POWER RATE

The firm Power Products and Services rate (FPS-07), or its successor, shall apply to the Surplus Firm Power purchased by Clallam under this Agreement and shall be priced as set forth below:

1. No later than thirty (30) days prior to the effective date of rates, charges or rebates, BPA shall unilaterally revise Table 1 of this Exhibit 1 of this Exhibit A to specify the demand, energy and other rates, charges or rebates that shall apply to the sale of Surplus Firm Power.

   HLH and LLH energy rates for Surplus Firm Power shall be set equal to the corresponding Priority Firm Rate, including any CRACs or DDCs, for energy plus the typical industrial margin used to establish the Industrial Firm Power Rate in BPA's most recently concluded wholesale power rate proceeding in which the typical industrial margin was established. For the WP-07 rate proceeding, the typical industrial margin is $0.57 per megawatt hour.

   The demand and other charges or rebates for Surplus Firm Power shall be set equal to the corresponding Priority Firm Rates, including any CRACs or DDCs if applicable, for demand and other charges or rebates.

2. The monthly load variation charge paid by Clallam for Surplus Firm Power shall be calculated using the sum of the Total Metered load and the amount of energy (in megawatt-hours) generated by Port Townsend's onsite co-generation during each month.

3. Unless otherwise agreed to by the Parties, if Total Metered Load exceeds 17 annual average megawatts (aMW) during a Contract Year, then the amount in excess of 17 annual aMW shall be billed at the UAI charge for energy applicable to any unauthorized increase for September of the Contract Year in which such exceedence occurred.

4. If an Emergency NFB Surcharge (Surcharge), or its successor, is triggered under the Priority Firm Rate, BPA shall establish, for the period the Surcharge is in effect, a dollar per megawatt hour surcharge applicable to Total Metered Load that BPA expects will result in an amount of additional revenue equal to the additional revenue it would have received if: (a) sales under this Agreement were subject to the Surcharge; and (b) the amount of Total Metered Load during the period the Surcharge is in effect was equal to the amount of Total Metered Load during the preceding Contract Year. The dollar per megawatt hour surcharge calculated pursuant to this section 4 will not be charged for any month during which there are no deliveries to Clallam of Surplus Firm Power under this Agreement.

Exhibit A, Table 1 Surplus Firm Power Rates August 17, 2006				
Month	**HLH Rate ($/MWh)**	**LLH Rate ($/MWh)**	**Demand Rate $/kW-Month**	**Load Variation Rate ($/MWh)**
October	30.27	22.33	1.94	0.47
November	32.25	23.67	2.08	0.47
December	33.63	24.83	2.18	0.47
January	28.64	20.87	1.85	0.47
February	29.23	21.07	1.88	0.47
March	27.16	20.06	1.75	0.47
April	25.52	18.50	1.64	0.47
May	21.41	14.98	1.36	0.47
June	19.44	10.59	1.25	0.47
July	23.81	17.58	1.53	0.47
August	27.78	20.75	1.79	0.47
September	28.66	23.11	1.85	0.47

Exhibit B
ADDITIONAL PRODUCTS, SERVICES, AND SPECIAL PROVISIONS

1. MONTHLY CO-GENERATION AMOUNTS
No later than three business days following the end of each month, Clallam shall provide or cause Port Townsend to provide to BPA in writing or by e-mail the total monthly amount of Port Townsend's onsite co-generation.

2. REVISIONS
This Exhibit B shall be revised upon mutual agreement of the Parties to reflect any new products, services, and special provisions that may be added during the term of this Agreement.

Exhibit C
POINTS OF MEASUREMENT FOR TOTAL METERED LOAD

Transmission Point of Delivery (Voltage) Point of Metering (Metering Voltage)	Metering Location	Manner of Service
Fairmount Transmission Point of Delivery (115 kV)		
Pt. Town New Mill Out Meter No. 2871 (115 kV)	Port Townsend Paper	Direct – BPA to Clallam