20.5 aMW POWER SALE TO PORT TOWNSEND PAPER CORPORATION FOR THE PERIOD JUNE 1, 2011, THROUGH AUGUST 31, 2013

ADMINISTRATOR'S RECORD OF DECISION

April 18, 2011

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I. INTRODUCTION

On November 13, 2009, the Bonneville Power Administration ("BPA") signed a block power sales contract (the "Block Contract") with Port Townsend Paper Corporation ("Port Townsend") and on the same date issued a Record of Decision on the Block Contract ("Port Townsend ROD"). On December 24, 2009, Port Townsend and BPA agreed to amend the Block Contract to change the date that the Block Contract terminates to May 31, 2011, consistent with BPA's then updated determination of equivalent benefits.[1] Under the Block Contract, BPA is selling up to 20.5 aMW of firm power to Port Townsend at the Industrial Firm (IP) power rate over approximately 19 months. Power deliveries began on November 15, 2009, and are scheduled to end May 31, 2011. This Record of Decision (ROD) documents BPA's final determination to offer a follow-on power sales contract to Port Townsend that will continue sales for a two year, three month period commencing on June 1, 2011 (the "2011 Contract").

Prior to making its final determination whether or not to offer the 2011 Contract, BPA provided an opportunity for public review and comment regarding the 2011 Contract and BPA's draft evaluation of the benefits and costs of serving Port Townsend ("Equivalent Benefits Test" or "EBT"). The public review and comment period took place from February 3, 2011, through February 23, 2011. BPA received comments from five parties: Alcoa Inc. (Alcoa), Public Power Council (PPC), Pacific Northwest Generating Cooperative (PNGC), Springfield Utility Board (SUB), and Industrial Customers of Northwest Utilities (ICNU).

As established in the Adminstrator's Record of Decision – Power Sale to Alcoa Inc. Commencing December 22, 2009 ("Alcoa ROD"), the Equivalent Benefits Test is the method BPA will use to determine whether a power sale to serve a DSI customer is consistent with sound business principles, absent a change in the holdings of the U.S. Court of Appeals for the Ninth Circuit in *PNGC I* and *PNGC II* or BPA's interpretation of these holdings.[2] The Administrator may offer a power sale only when it can be shown

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[1] See generally *Five-Month Extension of 20.5 aMW Power Sale Contract No. 09PB-12106 With Port Townsend Paper Company – Administrator's Record of Decision*, December 24, 2009 (Extension ROD).

[2] Pacific Northwest Generating Cooperative v. Department of Energy *(PNGC I)*, 550 F.3d 846 (9th Cir. 2008), *amended on denial of reh'g*, 580 F.3d 792 (9th Cir. 2009); Pacific Northwest Generating Cooperative v. Bonneville Power Administration *(PNGC II)*, 580 F.3d 828 (9th Cir. 2009), *amended on denial of reh'g*, 596 F.3d 1065 (9th Cir. 2010).

that the benefits to BPA of serving the DSI load equal or exceed BPA's cost of serving the load for the term of the contract.[3] Issues or comments pertaining to BPA's legal authority, BPA's interpretation of *PNGC I* and *II*, or related threshold matters have been comprehensively addressed in the Port Townsend ROD and the Alcoa ROD. Each of these records of decision are pending review in current litigation.[4] Therefore, BPA's legal authority, BPA's interpretation of *PNGC I* and *II*, or related threshold matters will not be reconsidered at this time and are not within the scope of this determination.

In addition, BPA's draft determination stated that the scope of review was limited to the draft EBT determination and did not include the EBT methodology. Therefore, general comments such as "BPA should abandon the EBT"and "the EBT has flawed assumptions" will not be addressed. Alcoa, DCPT10004; ICNU, DCPT10005 at 1. Specific comments on aspects of the EBT are addressed throughout the remainder of this ROD.

II. SUMMARY OF THE 2011 CONTRACT

The terms of the 2011 Contract are very similar to the terms of the current Block Contract described in the earlier Port Townsend ROD. BPA received one comment on the terms of the 2011 Contract. SUB, DCPT10006, at 5. This comment appears to be addressing the legality of including damage waiver language in DSI contracts. This issue has been addressed in the recently released DSI Lookback ROD and will not be revisited in this proceeding.[5]

a. Initial Term

The initial term of the 2011 Contract is two years and three months, beginning June 1, 2011, and ending August 31, 2013. Port Townsend has a recurring option to request that BPA conduct an EBT to determine if the term of the Agreement can be extended. This option can only be exercised after September 30, 2011, and cannot be exercised later than four months prior to the then-existing termination date. (See 2011 Contract, section 1.2.)

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[3] See *Power Sale to Alcoa Inc. Commencing December 22, 2009 – Administrator's Record of Decision*, December 21, 2009, at 8-9.

[4] On February 10, 2010, Industrial Consumers of Northwest Utilities ("ICNU") filed suit in the United States Court of Appeals for the Ninth Circuit contesting the Block Contract and the subsequent amendment extending the Block Contract. In addition, on January 22, 2010, Alcoa filed suit in the United States Court of Appeals for the Ninth Circuit contesting their own power sales agreement, which is the subject of the Alcoa ROD.

[5] See *Administrator's Record of Decision – Issues Remanded to Bonneville Power Administration in Pacific Northwest Generation Cooperative v. Department of Energy (PNGC I), 580 F.3d 792 (9th Cir. 2009) and Pacific Northwest Generating Cooperative v. Bonneville Power Administration (PNGC II), 596 F.3d 1065 (9th Cir. 2010),* February 18, 2010, at 22-23. Here, as there, BPA believes the provision is an appropriate means of limiting potential future financial risk to both parties in a commercial transaction of this kind.

ICNU commented that BPA has not provided any factual support for "its assumptions that Port Townsend would not enter into a shorter, less harmful contract . . . ." DCPT10005 at 1. First, the EBT solves for the longest possible contract term that still meets the requirement that benefits equal or exceed costs for the proposed term. Using this methodology, BPA determined the contract term of 27 months. Second, during negotiations, Port Townsend was clear that it is seeking the longest possible contract term because in order to remain in business it requires a stable, long-term power supply. In fact, in a letter commenting on the previous Block Contract, Port Townsend stated that "BPA's current unwillingness to offer a long-term power contract impairs the long-term planning so important to an industrial customer such as Port Townsend."[6] Moreover, Eveleen Muehlethaler, Vice President of Port Townsend Paper Company, has indicated as recently as March 18, 2011 in another public comment process that Port Townsend needs "to secure a long-term and affordable source of power."[7]

b. Rate

Purchases of Firm Power under the 2011 Contract are subject to the IP-10 Rate Schedule, or its successor. Port Townsend is subject to any applicable adjustments or charges established in BPA's then-effective Wholesale Power Rate Schedules and associated GRSPs.

c. Purchase and Sale of Firm Power

BPA shall sell, and Port Townsend shall purchase, up to 20.5 aMW of Firm Power on a take-or-pay basis, except as set forth in section 5.1 of the 2011 Contract. Port Townsend's Contract Demand was set at 20.5 MW in 1997, in Revision No. 1, Exhibit C of Contract No. DE-MS79-81BP90347. The Parties to the 2011 Contract recognize that Port Townsend is working with Jefferson County PUD No.1 (Jefferson) to develop an agreement to provide service to Port Townsend's Old Corrugated Container (OCC) recycling plant. To the extent Jefferson commences service to the OCC load, Port Townsend's Contract Demand will be reduced by 3.275 MW to reflect the change in status of that portion of the Port Townsend load and the OCC plant load shall no longer be included in Port Townsend's Total Plant Load. See 2011 Contract, Exhibit A. This reduction in Contract Demand, should it occur, is forecast to affect the EBT positively because the net revenues are negative in the later portion of the term. See Table 4.
Port Townsend is obligated to prepay each month for the Minimum Firm Power amount specified in section 4 of the 2011 Contract. If Port Townsend takes more than the Minimum Firm Power amount in a month, it will pay for that amount in the following

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[6] Letter from Marcus Wood, Attorney for Port Townsend Paper Corporation, to Allen Burns, Deputy Administrator, Bonneville Power Administration (Oct. 19, 2009) (on file with the BPA Public Affairs Office).

[7] See Comments of Eveleen Muehlethaler, Vice President, Port Townsend Paper Company, March 18, 2011 at 1; submitted in BPA's Contract High-Water Mark (CHWM) comment process and attached to this Record of Decision as Attachment E.

month. In addition, Port Townsend will pay BPA a security deposit of approximately $213,000 prior to the commencement of power deliveries to mitigate the payment risk exposure associated with power deliveries in a month in excess of the Minimum Firm Power amount. See 2011 Contract, Exhibit C, section 6. BPA also 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. See 2011 Contract, section 16.8.

d. Power Reserves

Port Townsend shall provide Supplemental Contingency Reserves in a manner consistent with the Minimum DSI Operating Reserve – Supplemental section of the 2010 GRSPs, or their successor, and Exhibit H to the 2011 Contract.

e. Take-or-Pay Mitigation

Port Townsend may request take-or-pay mitigation if it chooses to curtail its purchase obligation. Port Townsend will pay BPA damages for any curtailed amount equal to the amount by which the reasonable market value of the curtailed amount is less than the price of the IP-10 Rate, or its successor, including any credit for the value of reserves. Each month, Port Townsend will pay damages equal to the amount by which the product of the curtailed amount and the applicable IP rate, including any reserve credit, exceeds the product of the curtailed amount and the reasonable market value calculated pursuant to section 6.1 of the 2011 Block Contract.

III. THE EQUIVALENT BENEFITS DETERMINATION FOR THE PERIOD OF JUNE 1, 2011, THROUGH AUGUST 31, 2013

A key element of BPA's response to *PNGC II* was to implement the Equivalent Benefits Test to determine whether BPA could make a power sale to a DSI consistent with BPA's understanding of the Court's opinion. As established in the Port Townsend ROD and the Alcoa ROD, the EBT is intended to demonstrate that a decision to serve a DSI customer is consistent with sound business principles when it can be shown that the benefits to BPA of serving the DSI load would equal or exceed BPA's cost of serving the load during the term of service. In this evaluation of the 2011 Contract, BPA analysis indicates that it can supply firm power to Port Townsend and the likelihood that we will need to acquire power to serve the load during the term of the 2011 Contract is minimal because BPA anticipates serving the Port Townsend load from inventory under most water conditions. BPA then followed the steps (described in subsections a through d of this section) of the EBT to determine that it can provide service to Port Townsend for the term of the 2011 Contract, during which the forecast benefits of the sale exceed forecast costs by approximately $54,000.

a. BPA expects to be surplus during the 2011 Contract Period

BPA does not forecast the need to make purchases specifically to serve Port Townsend during the 2011 Contract under most water conditions. BPA has forecast a need to make some power purchases, including some normal "balancing" purchases in some months, to meet its total load obligations during the remainder of FY 2011 through August 2013, particularly under critical (*i.e.*, very poor) water conditions as explained below.[8]

The Equivalent Benefits Test is based on BPA's forecasts of average water in the 2010 White Book (Average Middle 80% Water Conditions), BPA's Initial Proposal in the BP-12 rate proceeding for FY 2012 through FY 2017 and BPA's recent streamflow expectations for FY 2011 that contributed to forecasts of hydroelectric generation – recent outputs of HYDSIM from December 2010 – that better reflect recent precipitation, as well as the lingering effects of the past two relatively dry water years.

BPA's most recent load and resources studies contained in the *2010 Pacific Northwest Loads & Resources Study* (the "2010 White Book") forecasts loads and resources for both the Federal system and the region as a whole for a 10-year period (Operating Years (OY) 2011-2020). In the 2010 White Book, BPA is forecast to have a surplus of approximately 1,160 aMW, 1,542 aMW, 1,557 aMW, and 1,602 aMW on an average annual basis under the middle 80 percent of historical water conditions for OY 2011, OY 2012, OY 2013, and OY 2014 respectively.[9] The term of the 2011 Contract includes 2 months in OY 2011 (June 1 through July 31, 2011), 12 months in each of OY 2012 and OY 2013, and 1 month in OY 2014 (August 2013). *See* 2010 White Book, Table 8 at 39, and Exhibits 11-14 at 104-111. The 20 aMW of power to be sold to Port Townsend under the 2011 Contract represents approximately one (1) percent of the forecast surpluses. Therefore, while BPA appreciates PPC's concern that BPA would be "exacerbating the risk that customers face from a poor water year," the risk associated with the 2011 Contract is small.

Moreover, even if one were to assume 1937-Critical Water Conditions, the impact of the 2011 Contract is negligible. The 2010 White Book projects a deficit of 501 aMW in OY 2011 (with DSI load of 271 aMW based on signed contracts for 340 aMW of service to the DSIs through May 2011), but projects a surplus of 113 aMW, 42 aMW, and 115 aMW on

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[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 2010 White Book is the 12-month period August 1 through July 31. For example, OY 2011 is August 1, 2010, through July 31, 2011. The value of 1,160 aMW of surplus for OY 2011 includes a DSI load of 271 aMW based on signed contracts for 340 aMW of service to the DSIs (320 aMW for Alcoa and 20 aMW for Port Townsend) through May 2011 and if the 271 aMW of DSI loads were removed from OY 2011 the surplus in OY 2011 would increase from 1,160 aMW to 1,431 aMW. The corresponding value for OY 2012 through OY 2014, years with 0 aMW of DSI load, would be 1,542 aMW, 1,557 aMW, and 1,602 aMW respectively.

an average annual basis under 1937-Critical Water Conditions during OY 2012, OY 2013 and OY 2014 respectively, assuming no augmentation and zero DSI load.[10]

As a result, BPA expects on an annual basis to be surplus under most water conditions and as such does not anticipate the need to alter its purchasing strategy for the sales that would be made to Port Townsend during the 2011 Contract. However, BPA may have to make short term purchases during certain times of the year to balance BPA's total loads and resources.

b. Benefits to BPA will equal or exceed costs for the period of the 2011 Contract

BPA forecasts that the revenues it will accrue from the firm sale of approximately 20 aMW to Port Townsend at the IP rate, under the 2011 Contract, would exceed by approximately $54,000 the forecast revenues BPA could otherwise obtain from selling that power into the market. See Tables 1-6 below. BPA's conclusion is that the sale of power to Port Townsend under the 2011 Contract satisfies the EBT.

Consistent with BPA's EBT methodology established in the Alcoa ROD and the earlier Port Townsend ROD, BPA's projected monthly revenues are determined by multiplying the heavy load hour (HLH) and light load hour (LLH) energy entitlements and demand entitlement by their respective IP rate components for each month. BPA has calculated revenues under the 2011 Contract based on a continuing sale of 20 aMW, as outlined in Table 1, of firm power each hour to Port Townsend under the IP rate schedule beginning June 1, 2011, and ending August 31, 2013. The energy and demand entitlements are the projected amounts to be sold by diurnal period each month during the term of the 2011 Contract. Since under the 2011 Contract BPA expects to make approximately 20 aMW available each month, 20 MW 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:

[10] 2010 White Book, page 40. While BPA has established some of its costs captured in its power rates for FY 2012 and FY 2013 based on 1937-Critical Water Conditions as evidenced by Table 4.1.1, BP-12-E-BPA-03A at 136-137, the net secondary energy revenues (surplus energy revenues less balancing power purchase costs), for FY 2012 and FY 2013 were based on the median net secondary energy revenues over the 70 water years as evidenced by Tables 19 and 20, BP-12-E-BPA-04A at 47-48.

Port Townsend EBT Analysis
TABLE 1 - Usage and Rates

Month	Port Townsend Usage			Projected IP Rates		
	Demand (kW)	HLH (MWh)	LLH (MWh)	Demand ($ / kW)	HLH ($ / MWh)	LLH ($ / MWh)
Jun-11	20,000	8,320	6,080	$1.32	$31.18	$23.29
Jul-11	20,000	8,000	6,880	$1.61	$33.33	$28.66
Aug-11	20,000	8,640	6,240	$1.89	$37.31	$31.40
Sep-11	20,000	8,000	6,400	$1.96	$36.49	$32.26
Oct-11	20,000	8,320	6,560	$9.35	$40.74	$30.93
Nov-11	20,000	8,000	6,420	$9.46	$41.26	$30.71
Dec-11	20,000	8,320	6,560	$10.13	$44.40	$34.23
Jan-12	20,000	8,000	6,880	$9.74	$42.56	$31.50
Feb-12	20,000	8,000	5,920	$9.75	$42.65	$31.64
Mar-12	20,000	8,640	6,220	$9.36	$40.78	$29.71
Apr-12	20,000	8,000	6,400	$8.57	$37.06	$26.54
May-12	20,000	8,320	6,560	$8.15	$35.11	$19.85
Jun-12	20,000	8,320	6,080	$8.39	$36.27	$20.50
Jul-12	20,000	8,000	6,880	$10.55	$46.43	$33.34
Aug-12	20,000	8,640	6,240	$10.99	$48.48	$35.15
Sep-12	20,000	7,680	6,720	$10.38	$45.58	$31.83
Oct-12	20,000	8,640	6,240	$9.35	$40.74	$30.93
Nov-12	20,000	8,000	6,420	$9.46	$41.26	$30.71
Dec-12	20,000	8,000	6,880	$10.13	$44.40	$34.23
Jan-13	20,000	8,320	6,560	$9.74	$42.56	$31.50
Feb-13	20,000	7,680	5,760	$9.75	$42.65	$31.64
Mar-13	20,000	8,320	6,540	$9.36	$40.78	$29.71
Apr-13	20,000	8,320	6,080	$8.57	$37.06	$26.54
May-13	20,000	8,320	6,560	$8.15	$35.11	$19.85
Jun-13	20,000	8,000	6,400	$8.39	$36.27	$20.50
Jul-13	20,000	8,320	6,560	$10.55	$46.43	$33.34
Aug-13	20,000	8,640	6,240	$10.99	$48.48	$35.15

TABLE 2 - BPA's Projected Revenue

Month	Revenues by Rate Determinant			Projected IP Revenue	
	Demand ($)	HLH ($)	LLH ($)	Month ($)	Cumulative ($)
Jun-11	$26,400	$259,418	$141,603	$427,421	$427,421
Jul-11	$32,200	$266,640	$197,181	$496,021	$923,442
Aug-11	$37,800	$322,358	$195,936	$556,094	$1,479,536
Sep-11	$39,200	$291,920	$206,464	$537,584	$2,017,120
Oct-11	$0	$338,957	$202,901	$541,858	$2,558,978
Nov-11	$0	$330,080	$197,158	$527,238	$3,086,216
Dec-11	$0	$369,408	$224,549	$593,957	$3,680,173
Jan-12	$0	$340,480	$216,720	$557,200	$4,237,373
Feb-12	$0	$341,200	$187,309	$528,509	$4,765,881
Mar-12	$0	$352,339	$184,796	$537,135	$5,303,017
Apr-12	$0	$296,480	$169,856	$466,336	$5,769,353
May-12	$0	$292,115	$130,216	$422,331	$6,191,684
Jun-12	$0	$301,766	$124,640	$426,406	$6,618,090
Jul-12	$0	$371,440	$229,379	$600,819	$7,218,910
Aug-12	$0	$418,867	$219,336	$638,203	$7,857,113
Sep-12	$0	$350,054	$213,898	$563,952	$8,421,065
Oct-12	$0	$351,994	$193,003	$544,997	$8,966,062
Nov-12	$0	$330,080	$197,158	$527,238	$9,493,300
Dec-12	$0	$355,200	$235,502	$590,702	$10,084,002
Jan-13	$0	$354,099	$206,640	$560,739	$10,644,741
Feb-13	$0	$327,552	$182,246	$509,798	$11,154,540
Mar-13	$0	$339,290	$194,303	$533,593	$11,688,133
Apr-13	$0	$308,339	$161,363	$469,702	$12,157,835
May-13	$0	$292,115	$130,216	$422,331	$12,580,166
Jun-13	$0	$290,160	$131,200	$421,360	$13,001,526
Jul-13	$0	$386,298	$218,710	$605,008	$13,606,534
Aug-13	$0	$418,867	$219,336	$638,203	$14,244,738

In this evaluation of a firm power sale to Port Townsend for the term of the 2011 Contract, BPA has, beginning in October 2011, used the proposed IP-12 energy and demand rates released in the Initial Proposal for the BP-12 rate proceeding in Tables 1 & 2.

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

BPA routinely shapes its inventory to meet the needs of its portfolio of contracts and sells its surplus inventory in the Pacific Northwest power market as described in BPA's BP-12 rate proceeding.[11] BPA routinely forecasts Mid-C electricity prices consistent with the methodology described in the BP-12 rate proceeding to value these purchases and sales.[12] In particular, BPA updated its natural gas price forecast – one of the inputs used to forecast electricity prices – for FY 2011 to reflect more contemporary natural gas fundamentals and BPA has utilized this update for the 4 months in FY 2011 that are part of this analysis.[13] The forecast of natural gas prices for FY 2012 and beyond was used in BPA's Initial Proposal in the BP-12 rate proceeding released November 2010.[14]

In the absence of selling 20 MW of firm power to Port Townsend's pulp and paper mill in every hour, BPA would have one less firm power requirement sale in its aggregated portfolio load shape. Therefore, BPA assumes, for purposes of the EBT analysis, that it would have approximately 20 aMW of surplus energy to sell in the market on an average annual basis. As illustrated in Table 3, BPA has forecast the revenues it would otherwise obtain from the market by incorporating BPA's updated inputs and assumptions in the development of the electricity price forecast used in this analysis of the 2011 Contract.[15]

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[11] Refer generally to the *Power Risk and Market Price Study* in the BP-12 rate proceeding; and specifically to section 2.5.2 for a more complete description of the operating risk factors BPA faces in the course of doing business and section 2.6.3 for surplus energy sales and revenue. See BP-12-E-BPA-04, beginning on pages 35 and 46.

[12] BPA employed its electricity price forecast for multiple purposes in the BP-12 rate proceeding as outlined in the *Power Risk and Market Price Study*. The study also details how BPA established its forecast of Mid-C electricity prices in the BP-12 rate proceeding. See generally sections 2.3 & 2.4 BP-12-E-BPA-04, beginning on page 15.

[13] See also discussion in section IV of this analysis and the *Short-Term Energy Outlook* from the EIA for March showing the EIA's forecast of the Henry Hub Spot Price average for 2011 of $4.10 per MMbtu with the spot price increasing to an average of $4.58 per MMbtu in 2012. *Short-term Energy Outlook*, DOE EIA, March 8, 2011, at 7.

[14] BPA's natural gas forecast used in the BP-12 rate proceeding is outlined beginning with section 2.3.1 of the *Power Risk and Market Price Study*. BPA's current understanding for FY2012 is that the economy will slowly recover while supply remains high. Even if production falls or demand increases, the ample amount of gas in storage should prevent prices from rising quickly. See BP-12-E-BPA-04, beginning on page 15.

[15] 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 energy revenues.

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

Month	Forecasted Market Price		Forecasted Revenues Obtained from the Market			
	HLH Price ($ / MWh)	LLH Price ($ / MWh)	HLH ($)	LLH ($)	Month ($) (HLH + LLH)	Cumulative ($)
Jun-11	$30.17	$22.73	$250,981	$138,205	$389,186	$389,186
Jul-11	$32.67	$25.56	$261,330	$175,841	$437,171	$826,357
Aug-11	$36.24	$28.63	$313,074	$178,631	$491,706	$1,318,063
Sep-11	$34.20	$27.78	$273,575	$177,807	$451,382	$1,769,445
Oct-11	$41.44	$32.61	$344,781	$213,922	$558,702	$2,328,147
Nov-11	$42.43	$33.22	$339,440	$213,272	$552,712	$2,880,860
Dec-11	$45.75	$36.51	$380,640	$239,506	$620,146	$3,501,005
Jan-12	$42.59	$32.33	$340,720	$222,430	$563,150	$4,064,156
Feb-12	$42.12	$32.07	$336,960	$189,854	$526,814	$4,590,970
Mar-12	$40.73	$30.73	$351,907	$191,141	$543,048	$5,134,018
Apr-12	$36.94	$26.35	$295,520	$168,640	$464,160	$5,598,178
May-12	$35.68	$21.17	$296,858	$138,875	$435,733	$6,033,911
Jun-12	$37.13	$22.24	$308,922	$135,219	$444,141	$6,478,051
Jul-12	$47.37	$34.84	$378,960	$239,699	$618,659	$7,096,711
Aug-12	$49.32	$36.61	$426,125	$228,446	$654,571	$7,751,282
Sep-12	$46.26	$33.16	$355,277	$222,835	$578,112	$8,329,394
Oct-12	$46.49	$35.68	$401,674	$222,643	$624,317	$8,953,711
Nov-12	$46.53	$34.65	$372,240	$222,453	$594,693	$9,548,404
Dec-12	$49.50	$38.40	$396,000	$264,192	$660,192	$10,208,596
Jan-13	$48.97	$37.11	$407,430	$243,442	$650,872	$10,859,468
Feb-13	$49.61	$37.64	$381,005	$216,806	$597,811	$11,457,279
Mar-13	$47.28	$35.13	$393,370	$229,750	$623,120	$12,080,399
Apr-13	$43.61	$33.17	$362,835	$201,674	$564,509	$12,644,907
May-13	$40.98	$24.97	$340,954	$163,803	$504,757	$13,149,664
Jun-13	$41.86	$25.19	$334,880	$161,216	$496,096	$13,645,760
Jul-13	$51.93	$38.28	$432,058	$251,117	$683,174	$14,328,935
Aug-13	$54.08	$40.14	$467,251	$250,474	$717,725	$15,046,659

As detailed in the Gas Price Forecast sub-section below, BPA's forecasts of natural gas prices for the Henry Hub have been progressing steadily downward since the WP-10 forecast of natural gas prices. The natural gas price forecast used in the 2010 Resource Program was reduced further. This was followed by a further reduction in the natural gas price forecast used in the Initial Proposal for the BP-12 rate proceeding. It is not unreasonable to assume that BPA's forecast of natural gas prices could decline further given market developments since September, when the gas price forecast for the Initial Proposal was completed.

Importantly, the EIA noted, in its March 8th article *Plentiful Water and Low Natural Gas Prices Cut Northwest Wholesale Power Prices in Half*, that "[s]ince the beginning of the year, Northwest wholesale power prices at the Mid-Columbia trading point have averaged 45% below the 5-year average (2006-2010) prices, and were well below the 5-year price range." If these twin trends of plentiful water and low natural gas prices were to continue, the benefits of IP sales to the DSIs would improve dramatically because the IP revenues would be unchanged – essentially a hedge against low market price outcomes. For example, if actual market prices turn out to be 45% lower than the forecasted market prices included in Table 3 of this analysis, then the Cumulative Forecast Revenues Obtained from the Market would be 45% lower, falling from $15,046,659 to $8,275,663 causing a Cumulative Net Benefit (IP-Market) to BPA of $5,969,075, which would be a $6,770,997 improvement compared to the ($801,922) in Table 4 below.

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:

TABLE 4 - BPA's Net Benefit before Adjustment

Month	Net Revenue or (Cost) Month ($)	Net Revenue or (Cost) Cumulative ($)
Jun-11	$38,235	$38,235
Jul-11	$58,850	$97,085
Aug-11	$64,389	$161,473
Sep-11	$86,202	$247,675
Oct-11	($16,845)	$230,830
Nov-11	($25,474)	$205,356
Dec-11	($26,189)	$179,167
Jan-12	($5,950)	$173,217
Feb-12	$1,694	$174,911
Mar-12	($5,912)	$168,999
Apr-12	$2,176	$171,175
May-12	($13,402)	$157,773
Jun-12	($17,734)	$140,039
Jul-12	($17,840)	$122,199
Aug-12	($16,368)	$105,831
Sep-12	($14,160)	$91,671
Oct-12	($79,320)	$12,351
Nov-12	($67,455)	($55,104)
Dec-12	($69,490)	($124,593)
Jan-13	($90,133)	($214,726)
Feb-13	($88,013)	($302,739)
Mar-13	($89,527)	($392,266)
Apr-13	($94,806)	($487,072)
May-13	($82,426)	($569,498)
Jun-13	($74,736)	($644,234)
Jul-13	($78,166)	($722,400)
Aug-13	($79,522)	($801,922)

d. 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.

Consistent with the methodology described in the Alcoa ROD and the earlier Port Townsend ROD, BPA has identified a number of tangible benefits to BPA that would not be achieved by a market sale of power as compared to selling the same power to Port Townsend at the IP rate during the period of the 2011 Contract. BPA conducted an economic analysis to determine the net value of those benefits.

BPA believes its forecast of positive net revenues is probably conservative, inasmuch as the sales to DSIs encompass certain additional intangible and qualitative benefits to BPA's operations.[16] 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 2011 Contract. Adjustments for these or other benefits may affect the tenor and/or megawatt amount of future sales.

Value of Reserves

The 2011 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 of the reserves Port Townsend is required to make available to BPA during the period of the 2011 Contract. Sales at the IP rate reflect the value of BPA's right to obtain contingency reserves.[17] Specifically, the energy rate tables in the IP-10 rate schedule and the proposed IP-12 rate schedule include an $0.80 per MWh credit and a $0.95 per MWh credit, respectively, 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 credit for the value of reserves in the applicable rate schedule.[18] As illustrated by Table 5a, this is done for every megawatt hour not sold to Port Townsend:

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[16] See Alcoa ROD at 72-82.

[17] Sales at the IP rate require the provision of the Minimum DSI Operating Reserve – Supplemental. The 2011 Contract is a sale at the IP rate and, accordingly, Port Townsend is required to make such contingency reserves available to BPA, as specified in section 5.2 and implemented by Exhibit H to the 2011 Contract.

[18] 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.

TABLE 5a - BPA's Net Benefit Adjustments

Month	Value of Reserves Month ($)	Value of Reserves Cumulative ($)
Jun-11	$11,520	$11,520
Jul-11	$11,904	$23,424
Aug-11	$11,904	$35,328
Sep-11	$11,520	$46,848
Oct-11	$14,136	$60,984
Nov-11	$13,699	$74,683
Dec-11	$14,136	$88,819
Jan-12	$14,136	$102,955
Feb-12	$13,224	$116,179
Mar-12	$14,117	$130,296
Apr-12	$13,680	$143,976
May-12	$14,136	$158,112
Jun-12	$13,680	$171,792
Jul-12	$14,136	$185,928
Aug-12	$14,136	$200,064
Sep-12	$13,680	$213,744
Oct-12	$14,136	$227,880
Nov-12	$13,699	$241,579
Dec-12	$14,136	$255,715
Jan-13	$14,136	$269,851
Feb-13	$12,768	$282,619
Mar-13	$14,117	$296,736
Apr-13	$13,680	$310,416
May-13	$14,136	$324,552
Jun-13	$13,680	$338,232
Jul-13	$14,136	$352,368
Aug-13	$14,136	$366,504

Avoided Transmission and Ancillary Services Expenses

When BPA makes a sale to a DSI, all 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 the Mid-Columbia trading hub (Mid-C); thus the seller pays for the cost of transmission to that delivery point. Power Services (PS) is the organization within BPA that is responsible for the marketing of Federal power. PS must pay the transmission and ancillary services costs to move surplus power to the Mid-C delivery point in order to realize the full market value for its surplus sales. PS maintains an inventory of transmission products and services to deliver the surplus power it intends to sell. However, this transmission product inventory is not sufficient to deliver all of the surplus power PS would sell under all load and resource conditions, especially under high stream flows. As a result, there is a subset of load and resource conditions under which PS would incur incremental costs for transmission and ancillary services to deliver incremental surplus energy sales, if PS did not sign contracts to serve the DSI loads. The incremental transmission and ancillary services costs are avoided when BPA makes IP sales to the DSIs because DSIs contract for their own transmission and ancillary services. The planned transmission and ancillary services expenses to address both the expected expenses and their uncertainty were addressed in the WP-10 rate proceeding, in BPA's Initial Proposal for the BP-12 rate proceeding, and are expected to be addressed in each subsequent BPA rate proceeding.[19]

PS valued these avoided transmission and ancillary services costs for the period of the 2011 Contract using the same methodology used in both the WP-10 and BP-12 rate proceedings to establish the total costs and risks associated with PS's inventory of transmission products and services. In these computations, both fixed, take-or-pay costs and variable incremental transmission and ancillary service costs were computed under 3,500 load and resource conditions for each month. Incremental transmission and ancillary services costs were computed by comparing the amount of surplus energy available to the monthly excess amount of firm transmission products in the PS inventory.

Tariff costs established by BPA's Transmission Services organization were applied to the amount of surplus energy in excess of the PS transmission products inventory. Total monthly transmission and ancillary services costs were computed assuming no service to the DSIs and DSI service of 340 aMW for the period beginning June 1, 2011, through December 31, 2012.[20] The average total monthly expense values of the 3,500 games were computed with and without service to the DSIs and the differences were taken to determine the avoided PS transmission and ancillary services costs when PS makes these

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[19] Refer to section 4 of the *Revenue Requirement Study*, WP-10-FS-BPA-02 and section 2.4.9 of the *Risk Analysis and Mitigation Study and Documentation* WP-10-FS-BPA-04/04A in the WP-10 rate proceeding. Refer to section 4 of the *Power Revenue Requirement Study*, BP-12-E-BPA-02 and section 2.2.2.5 of the *Power Risk and Market Price Study*, BP-12-E-BPA-04 in the BP-12 rate proceeding.

[20] This number is comprised of 320 aMW for Alcoa and 20 aMW for Port Townsend Paper Company. A concurrent EBT analysis demonstrates that BPA would be able, consistent with sound business principles, to provide service to Alcoa through December 2012. See Attachment B. Based on the analysis in Attachment B, and for purposes of this analysis only, it is reasonable to assume that BPA would amend Alcoa's existing contract to provide for an extension of service or offer Alcoa a new contract upon the expiration of their existing contract in the event the EBT continues to apply as the appropriate test for service. Given that assumption coupled with BPA's prior determinations that the accrual of other potential benefits associated with [the block sale to Port Townsend] could be significant if the accumulation of additional sales to the DSIs in total were taken into account, BPA credited Port Townsend its proportional share of the Avoided Transmission and Ancillary Services Expenses and Demand Shift benefits for the period that the EBT analysis demonstrates Alcoa would be provided service (i.e. through December 2012). See Port Townsend ROD at 11 and Extension ROD at 1. If these two benefits were only credited to Port Townsend through May 26, 2012 (end of Extended Initial Period of the Alcoa Contract, *ROD Granting Alcoa's Request to Extend the Initial Period of Alcoa's Power Sales Agreement*, released October 29, 2010, at 5) the EBT analysis demonstrates that service could still be provided to Port Townsend through May 31, 2013, with projected revenues exceeding costs by approximately $50,000. See Attachment C.

IP sale(s) to the DSIs. For purposes of this analysis, Port Townsend has been allotted 5.9% of this PS benefit in each month as illustrated in Table 5b below. This percent allotment is the result of the proportion of the megawatt amounts during the period of the 2011 Contracts, and as depicted in Table 1 above.

<u>TABLE 5b - BPA's Net Benefit Adjustments</u>

	Avoided Tx and Ancillary Service Costs		
Month		Proportional	
	Month ($)	Month ($)	Cumulative ($)
Jun-11	$277,342	$16,314	$16,314
Jul-11	$85,751	$5,044	$21,358
Aug-11	$0	$0	$21,358
Sep-11	$0	$0	$21,358
Oct-11	$8,526	$502	$21,860
Nov-11	$22,634	$1,331	$23,191
Dec-11	$70,298	$4,135	$27,327
Jan-12	$275,908	$16,230	$43,556
Feb-12	$229,707	$13,512	$57,069
Mar-12	$238,162	$14,010	$71,078
Apr-12	$406,871	$23,934	$95,012
May-12	$631,194	$37,129	$132,141
Jun-12	$524,069	$30,828	$162,968
Jul-12	$246,818	$14,519	$177,487
Aug-12	$43,497	$2,559	$180,046
Sep-12	$20,371	$1,198	$181,244
Oct-12	$12,378	$728	$181,972
Nov-12	$32,792	$1,929	$183,901
Dec-12	$77,506	$4,559	$188,460
Jan-13	$0	$0	$188,460
Feb-13	$0	$0	$188,460
Mar-13	$0	$0	$188,460
Apr-13	$0	$0	$188,460
May-13	$0	$0	$188,460
Jun-13	$0	$0	$188,460
Jul-13	$0	$0	$188,460
Aug-13	$0	$0	$188,460

BPA continues to value avoided transmission and ancillary services costs for the period of the 2011 Contract using the tariff costs adopted by Transmission Services in the TR-10 rate proceeding. The 2012-2013 transmission rate case parties reached a partial rate case settlement, agreeing that the transmission and ancillary service tariffs will remain unchanged. As a result, BPA has continued to use the tariff costs adopted in the TR-10 rate proceeding in this analysis.

Demand Shift

When BPA serves the DSI loads – including Port Townsend – and they operate – as opposed to not operating if BPA does not sell to them – 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. For a given energy inventory condition, these higher prices increase BPA's surplus energy revenues and balancing purchase power costs. However, given that BPA forecasts annual energy surpluses ranging from 1,100 aMW to 1,600 aMW under average water conditions, the increase in surplus energy revenues is expected to be greater than the increase in balancing power purchase costs, resulting in higher net revenues. BPA estimated the lower price impact of serving no DSI load by reducing loads in the PNW by 340 aMW for each of the 3,500 games simulated by AURORA.[21] Results of this analysis indicate that the mean annual price forecast is lower by $0.42 per MWh and $0.47 per MWh for fiscal years 2012 and 2013, respectively, relative to the simulated monthly electricity market price forecast through December 31, 2012, reported in Table 3.

Specifically, the monthly demand shift values in the Month ($) column of Table 5c are the difference between the averages of two distributions of BPA's net revenues. The first distribution of BPA's net revenues is the result of multiplying the forecast distribution of monthly market prices that *included the 340 aMW reduction to PNW loads* by the forecast distribution of BPA's inventories. The second distribution of BPA's net revenues is the result of multiplying the forecast distribution of monthly market prices that *included no change to PNW loads* (i.e., the 340 aMW load is included in the PNW loads) by the same forecast distribution of BPA's inventories. For the purposes of this EBT analysis, Port Townsend has been allotted 5.9% of this benefit to BPA in each month as illustrated in the Proportional Month ($) column of Table 5c below. This percent allotment is the result of the proportion of the megawatt amounts in the period of the 2011 Contract, and as depicted in Table 1 above, as compared to the 340 aMW forecasted for all DSI customers.

[21] 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 ($)
Jun-11	$231,819	$13,636	$13,636
Jul-11	$59,053	$3,474	$17,110
Aug-11	($170,339)	($10,020)	$7,090
Sep-11	($79,296)	($4,664)	$2,426
Oct-11	($58,137)	($3,420)	($994)
Nov-11	$32,607	$1,918	$924
Dec-11	$32,513	$1,913	$2,836
Jan-12	$389,460	$22,909	$25,746
Feb-12	$340,733	$20,043	$45,789
Mar-12	$481,712	$28,336	$74,125
Apr-12	$571,432	$33,614	$107,739
May-12	$1,244,548	$73,209	$180,947
Jun-12	$1,174,751	$69,103	$250,050
Jul-12	$533,197	$31,365	$281,415
Aug-12	$103,935	$6,114	$287,529
Sep-12	$61,947	$3,644	$291,173
Oct-12	($45,776)	($2,693)	$288,480
Nov-12	$103,379	$6,081	$294,561
Dec-12	$110,588	$6,505	$301,066
Jan-13		$0	$301,066
Feb-13		$0	$301,066
Mar-13		$0	$301,066
Apr-13		$0	$301,066
May-13		$0	$301,066
Jun-13		$0	$301,066
Jul-13		$0	$301,066
Aug-13		$0	$301,066

Conclusion of Equivalent Benefits Test

Table 6 below illustrates that the financial benefits BPA expects to receive from making an IP sale to Port Townsend during the period of the 2011 Contract (from June 1, 2011 through August 31, 2013) exceed by approximately $54,000 the forecasted revenues that BPA would otherwise obtain from selling this power on the wholesale electricity market. BPA's methodology for making this determination is based, to the extent possible, on modeling tools used in BPA's rate cases. That process includes discovery, testimony, rebuttal testimony, and cross examination prior to a final determination by the Administrator. Further, this analysis is marked by thorough and thoughtful consideration of market fundamentals and other factors that ensure the integrity of the results.

TABLE 6 - BPA's Net Benefit after Adjustments

	BPA's Adjusted Net Revenue or (Cost)					
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 ($)	Cumulative Total Contract-to-Date ($)
Jun-11	$38,235	$11,520	$16,314	$13,636	$79,705	$79,705
Jul-11	$58,850	$11,904	$5,044	$3,474	$79,272	$158,977
Aug-11	$64,389	$11,904	$0	($10,020)	$66,273	$225,250
Sep-11	$86,202	$11,520	$0	($4,664)	$93,057	$318,307
Oct-11	($16,845)	$14,136	$502	($3,420)	($5,627)	$312,680
Nov-11	($25,474)	$13,699	$1,331	$1,918	($8,526)	$304,154
Dec-11	($26,189)	$14,136	$4,135	$1,913	($6,005)	$298,149
Jan-12	($5,950)	$14,136	$16,230	$22,909	$47,325	$345,474
Feb-12	$1,694	$13,224	$13,512	$20,043	$48,474	$393,948
Mar-12	($5,912)	$14,117	$14,010	$28,336	$50,550	$444,498
Apr-12	$2,176	$13,680	$23,934	$33,614	$73,403	$517,901
May-12*	($13,402)	$14,136	$37,129	$73,209	$111,072	$628,974
Jun-12	($17,734)	$13,680	$30,828	$69,103	$95,876	$724,850
Jul-12	($17,840)	$14,136	$14,519	$31,365	$42,179	$767,029
Aug-12	($16,368)	$14,136	$2,559	$6,114	$6,440	$773,469
Sep-12	($14,160)	$13,680	$1,198	$3,644	$4,362	$777,832
Oct-12	($79,320)	$14,136	$728	($2,693)	($67,149)	$710,683
Nov-12	($67,455)	$13,699	$1,929	$6,081	($45,746)	$664,937
Dec-12	($69,490)	$14,136	$4,559	$6,505	($44,289)	$620,648
Jan-13	($90,133)	$14,136	$0	$0	($75,997)	$544,651
Feb-13	($88,013)	$12,768	$0	$0	($75,245)	$469,406
Mar-13	($89,527)	$14,117	$0	$0	($75,410)	$393,997
Apr-13	($94,806)	$13,680	$0	$0	($81,126)	$312,870
May-13	($82,426)	$14,136	$0	$0	($68,290)	$244,581
Jun-13	($74,736)	$13,680	$0	$0	($61,056)	$183,525
Jul-13	($78,166)	$14,136	$0	$0	($64,030)	$119,494
Aug-13	($79,522)	$14,136	$0	$0	($65,386)	$54,109

* The values for the month of May-12 for Net Revenue or (Cost) in column (A) and Value of Reserves in colunn (B) are now consistent with the values for May-12 displayed in Tables 4 and 5a from the draft determination. This causes the Cumulative Total for the 2011 Contract-to-Date to be $54,109 in Aug-13, as opposed to the $54,037 displayed in the draft determination.

IV. ADDITIONAL ISSUES

a. Whether BPA's gas price forecast is reasonable.

One contentious issue raised in the past by parties is whether BPA's gas price forecast is reasonable. The gas price forecast is an important component of BPA's electricity price forecast 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. This issue was again raised by PPC:

> BPA attempted to use the underlying variability inherent in the natural gas price forecast to argue that it's [sic] natural gas price forecast is, if anything, conservative, since gas prices have been declining recently.

DCPT10007 at 2. This section addresses BPA's gas price forecast approach and demonstrates that BPA's natural gas price forecast is reasonable in light of the geopolitical risks asserted by PPC, is reasonable compared to a recent history of monthly average Henry Hub spot prices for natural gas and is reasonable compared to what other industry experts are expecting.

As described below, BPA's forecast of natural gas prices is based on sound analytics and reflects a reasonable approach and methodology. For this analysis, BPA utilized its most recent gas price forecast for the four months in FY 2011 together with the gas price forecast from the BP-12 rate proceeding for all subsequent months. This forecast is labeled "BPA (Nov/Sep-10)" in Figure 1.

Specifically, BPA's current natural gas price forecast for FY 2011 – 4 months of which are encompassed by the 2011 Contract – was updated in November 2010 to better reflect three main natural gas market fundamentals: a) continued strength of natural gas production, despite steep reductions in rig counts since late 2008, b) consistent but sluggish recovery of natural gas demand, partially due to the nature of the economic recovery, and c) ample amount of natural gas in storage, in conjunction with the resiliency of domestic gas production, has contributed to downward pressure on prices in the near term.[22] The current withdrawal season provides evidence of the above fundamentals. Seasonal demand during winter 2010 was well above average due to persistent cold weather across most of the nation, which led to larger than expected withdrawals from storage. Still, prices failed to rally as a result, with Henry Hub reaching a monthly high of less than \$4.50 per MMbtu during January 2011. The amount of gas in storage, while currently projected to end the withdrawal season at approximately 1.6

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[22] In addition, BPA has detailed, with contemporary information from the Energy Information Administration in Attachment A ("Natural Gas Statistics"), the continued strength of natural gas production despite steep declines in rigs, the sluggish recovery of natural gas demand (in that growth in natural gas demand is slower than growth in natural gas production), and the ample amount of natural gas in storage. See also Short-Term Energy Outlook for March showing the EIA's forecast Henry Hub Spot Price average for 2011 remains low at \$4.10 per MMbtu, *Short-term Energy Outlook*, DOE EIA March 8, 2011, at 7.

trillion cubic feet, is still above the five year average. See Attachment A. The evidence of continued strength of production is substantiated by the weak rally in winter gas prices in the face of an extremely cold winter, and is expected to weigh heavily on prices throughout the remainder of FY 2011.

BPA's natural gas price forecast used for the Initial Proposal in the BP-12 rate proceeding was used to analyze the 2011 Contract during FY 2012 and all subsequent months. This natural gas price forecast was completed by BPA in September 2010, during BPA's fourth quarter of its fiscal year. The methodology for its development and its use as an input to BPA's electricity price forecasts are outlined in section 2.3.1 of the *Power Risk and Market Price Study* (see BP-12-E-BPA-04, beginning on p. 15).

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: Bentek Energy LLC (Bentek), Cambridge Energy Research Associates (CERA), the United States Department of Energy's Energy Information Administration (EIA), PIRA Energy Group, and Wood Mackenzie.[23] 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 June 2010 through March 2011.

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[23] With the exception of the EIA, each of these forecasters considers their information to be proprietary. The vintage of these forecasts is fall 2010 to March 2011. The EIA forecast in BPA's Draft Determination was from their *Short-term Energy Outlook* released January 11, 2011. At that time, the EIA's next *Short-term Energy Outlook* was to be released February 8, 2011. In their comments, SUB suggested that BPA should use this newer forecast. DCPT10006 at 5. BPA has used the EIA's March 2011 forecast in Figure 1.

Figure 1: Henry Hub Natural Gas Spot Price Forecast

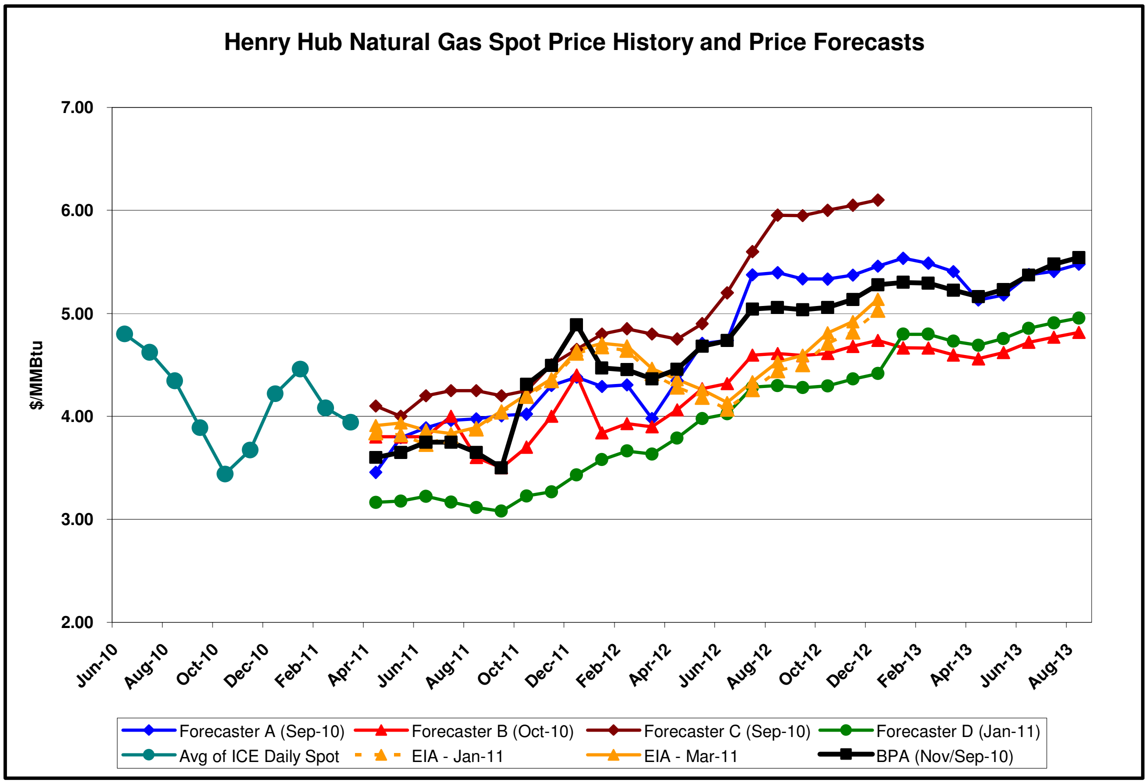
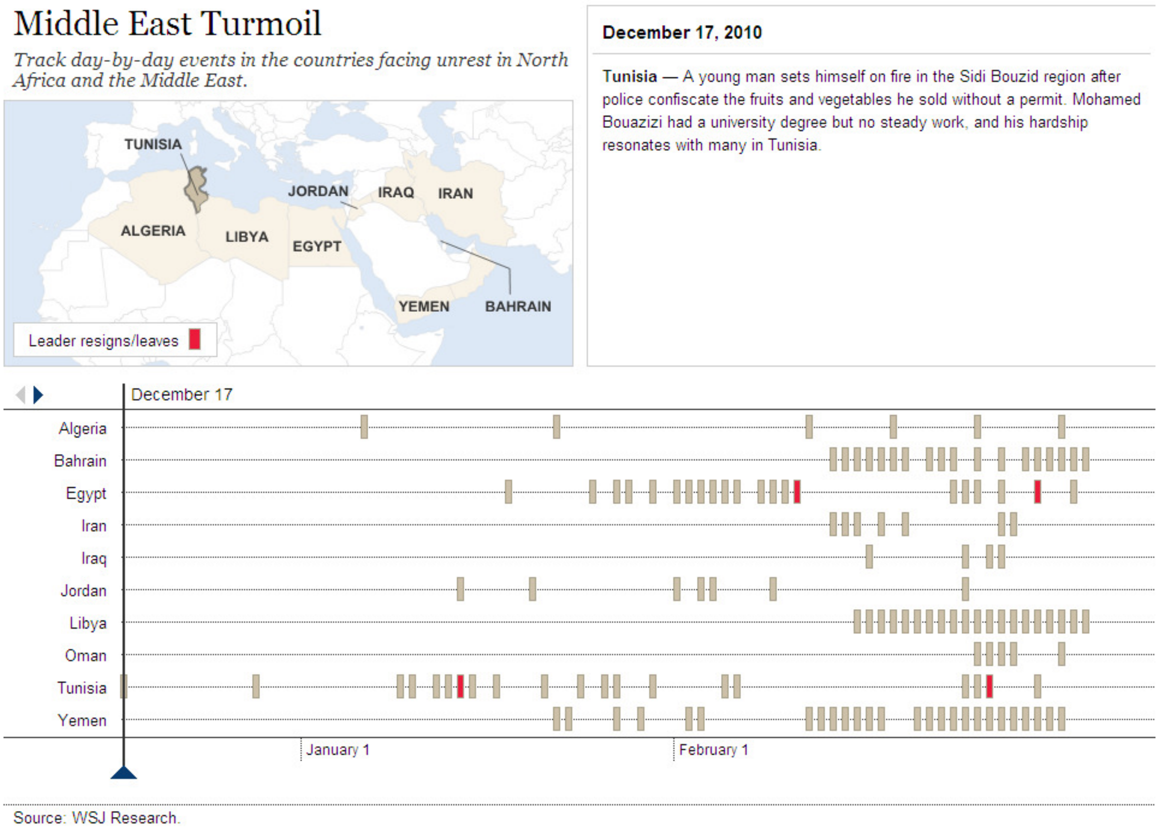


Figure 1 demonstrates that recent spot market prices for natural gas at the Henry Hub have been less than $5 per MMBtu from June 2010 through March 2011. This illustration also demonstrates that the forecasts of five other industry experts are between $3.22 per MMBtu and $4.20 per MMBtu for June 2011 – the starting month of BPA's evaluation of equivalent benefits for the 2011 Contract – and their forecasts remain lower than $5 per MMBtu through May 2012 the month in which the EIA forecasts that Henry Hub spot prices for natural gas will average $4.18 per MMBtu. BPA's updated forecast of spot prices for natural gas at the Henry Hub is consistent with the views reflected by these five industry experts.

Moreover, natural gas prices have not exhibited similar behavior to the increase in the price of Brent Sea crude oil in response to the "ongoing and unpredictable turmoil in the Middle East," as asserted by PPC. DCPT10007 at 2. We agree that the ongoing turmoil in the Middle East is indeed unpredictable; it was ignited December 17, 2010, in Tunisia and has since spread to at least 10 countries in the Middle East and North Africa according to the *Wall Street Journal* and illustrated in Figure 2:

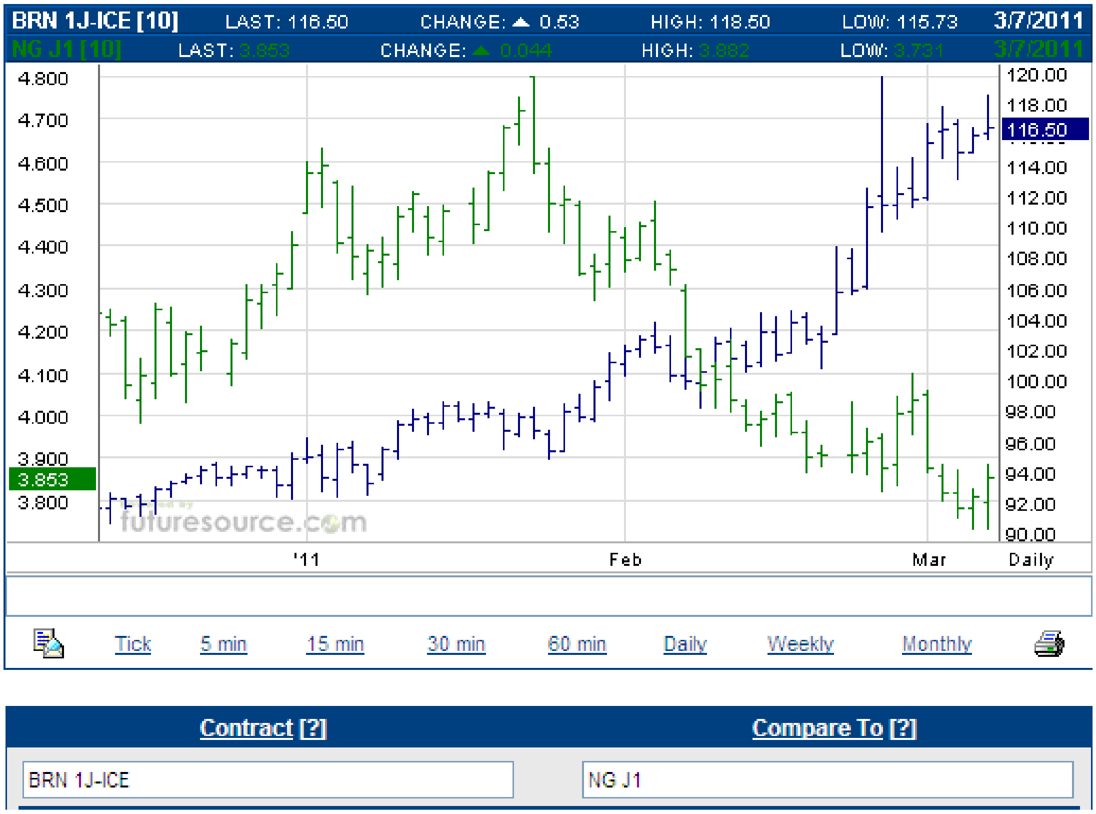
Figure 2 – Turmoil in the Middle East



Source: Wall Street Journal (online edition), March 7, 2011.

Given that PPC did not provide any specific citation for the Brent Crude price of oil being $112, we have compared the prompt month futures contracts – April 2011 – of both Brent Crude Oil on the InterContinental Exchange (symbol = BRN 1J-ICE) and Henry Hub Natural Gas on the New York Mercentile Exchange (symbol = NG J1) for the period December 15, 2010 (2 days before the December 17th date the *Wall Street Journal* identifies as the ignition of the turmoil) through March 7, 2011.

Figure 3 – Comparison of Brent Crude and Natural Gas

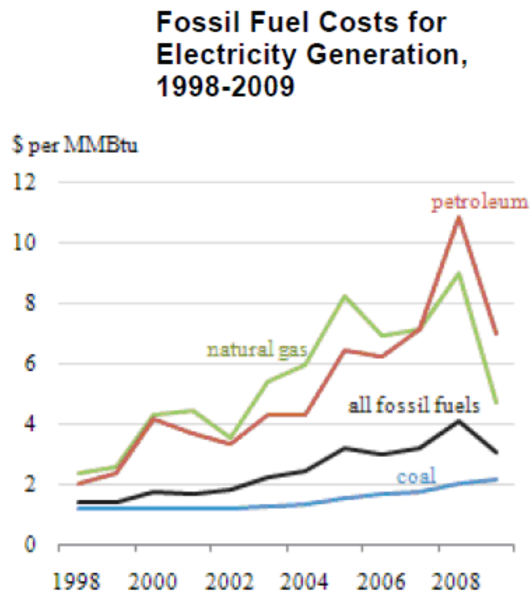


Source: Wall Street Journal (online edition), March 7, 2011.

As shown in Figure 3, the price of Brent Crude has increased from $92.26 per barrel on December 15, 2010 to close at $116.50 per barrel on March 7, 2011, an *increase* of 26.3 percent. However, over the same period, Figure 3 also illustrates a *decrease* of 8.6 percent in the price of natural gas from a close of $4.216 per MMbtu on December 15, 2010 to a mid-day trade of $3.853 per MMbtu on March 7, 2011. Therefore, we disagree with PPC's assertion that the turmoil in the Middle East is evidence of "significant upside risk in the natural gas price forecast." DCPT10007 at 2.

Furthermore, the price relationship observed in the April 2011 futures contracts for Brent Crude Oil and Henry Hub Natural Gas is not isolated to that single futures contract. The inverse nature of the relationship pre-dates the turmoil in the Middle East. Specifically, when the prices for crude oil and natural gas are illustrated in consistent units, namely MMbtu, it is evident that prices for natural gas have been below prices for crude oil since 2009 on an average annual basis.

Figure 4 – Fossil Fuel Costs for Electricity Generation, 1998-2009



Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Prior to that time, as illustrated in Figure 4, relative fossil fuel costs may have contributed to the "substitutability of oil and natural gas in various applications" as PPC argues. See DCPT100007 at 2. However, since the chart in Figure 4 was published, the price of crude oil has risen substantially as PPC has observed to $20 per MMbtu ($116.50 per barrel Brent Crude oil on March 7, 2011 divided by 5.8 MMbtu per barrel equates to approximately $20 per MMbtu[24]), while the price of natural gas has fallen to $3.83 per MMbtu (on March 7, 2011) and the price of coal has risen.[25] This has led the Energy Information Administration (EIA) to focus more on the substitutability of natural gas and coal, and not the substitutability of natural gas and oil:

> The increase in delivered coal prices and the decrease in delivered natural gas prices, combined with surplus capacity at highly-efficient gas-fired combined-cycle plants resulted in coal-to-gas fuel switching. This

[24] 5.8 million british thermal units (MMbtu) per barrel taken from http://www.eia.doe.gov/energyexplained/index.cfm?page=about_energy_units. Other industry sources use conversions ranging from 5.4 to 5.8 MMbtu per barrel. For example, the BP Statistical Review of World Energy for 2010 uses a conversion of 5.41 MMbtu per barrel of oil equivalent.

[25] "The price of natural gas delivered to electric power plants fell in 2009 to roughly half the 2008 level. In 2009, annual average natural gas wellhead prices reached their lowest level in 7 years. Increased supply due to the availability of shale gas, coupled with mild winter temperatures and higher production, and storage levels, and significant expansions of pipelines capacity also worked to put downward pressure on natural gas prices. At the same time, the cost of coal rose 6.8 percent (Table 3.8), largely due to long-term contracts signed prior to the recent recession. Between 2000 and 2009, coal prices to electric power plants rose 84 percent." *Electric Power Annual 2009,* U.S. Energy Information Administration at 1.

> occurred particularly in the Southeast (Alabama, Arkansas, Florida, Georgia, Mississippi, and South Carolina) and also Pennsylvania. Nationwide, coal-fired electric power generation declined 11.6 percent from 2008 to 2009, bringing coal's share of the electricity power output to 44.5 percent, the lowest level since 1978. Coal consumption at U.S. power plants paralleled the decline in generation, dropping 10.3 percent from 2008.

United States Energy Information Administration, *Electric Power Annual 2009*, November 2010 at 1.

Nonetheless, the price of natural gas has continued to decline recently for the same reasons discussed earlier and detailed in Attachment A: a) continued strength of natural gas production, despite steep reductions in rig counts since late 2008, b) consistent but sluggish recovery of natural gas demand, partially due to the nature of the economic recovery, and c) ample amount of natural gas in storage which contributes to downward pressure on prices in the near term.[26]

As a result, BPA believes its natural gas price forecast contained in this analysis of equivalent benefits for the Port Townsend contract is reasonable in light of the geopolitical risks asserted by PPC, is reasonable compared to a recent history of monthly average Henry Hub spot prices for natural gas and is reasonable compared to what other industry experts are expecting.

Decision: BPA's natural gas price forecast is reasonable.

b. Whether BPA can elect to serve Port Townsend without performing an EBT analysis to determine whether, consistent with BPA's understanding of *PNGC II*, such a sale would be consistent with sound business principles.

PNGC comments that BPA "has not put forth a persuasive explanation for why it treats its proposed decision to serve PT Paper in the same manner that it has treated its decision to serve Alcoa's Intalco Works smelter at Ferndale." DCPT10008 at 2. In support of PNGC's apparent conclusion that BPA should apply different factors to Port Townsend and Alcoa when making DSI service decisions, PNGC points to economic differences between the two DSIs and states that: "Nothing in the Ninth Circuit's decisions in *PNGC I* and *PNGC II* cases supports the use of a cookie cutter approach to BPA's decisionmaking regarding service to PT Paper." *Id.*

BPA disagrees with PNGC's characterization of the EBT and its conclusion. BPA adopted the EBT methodology in response to the court's direction in *PNGC II* that Industrial Firm Power sales to the DSIs must be "consistent with sound business principles." 580 F.3d at 1065. There is nothing in either opinion to suggest that the court did not intend for this standard to apply to sales to all DSIs. In fact, in *PNGC I*, the court states:

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[26] OpCit.

> BPA's contract with Clallam/Port Townsend suffers from the same central deficiency as BPA's contracts with the aluminum DSIs. Namely, BPA, although under no obligation to supply Port Townsend with power, has nonetheless agreed to sell power to the paper company at a rate below both the market rate and the IP rate. The agency provides no unique reasons to explain why supplying Port Townsend with subsidized energy is consistent with "sound business principles."

580 F.3d 792, 824 (9th Cir. 2009). In response to the Court's view that the Port Townsend contract was defective for the same reasons that it viewed the Alcoa contract as defective, BPA has decided to apply the same standard—currently the EBT analysis—to all sales to the DSIs at the Industrial Firm Power rate.

BPA is aware of the differences between Alcoa and Port Townsend. By no means does BPA take a "cookie cutter approach" either when contracting with differently situated customers or providing customer service and support during the term of any contract. However, as long as Port Townsend is a DSI purchasing Industrial Firm Power, the legal mandates handed down by the Ninth Circuit Court of Appeals in *PNGC I* and *II* apply to all DSI customers.

Decision: Based on BPA's current interpretation of *PNGC I* and *II* and absent further direction from the Court, BPA will continue to use the EBT methodology to evaluate whether or not Industrial Firm Power sales to Port Townend are consistent with sound business principles.

c. Whether BPA's approach to providing DSI service is inconsistent with the Tiered Rate Methodology.

ICNU makes the following argument:

> Offering Port Townsend a contract at cost-based rates is also inconsistent with BPA's findings that it has insufficient cost-based power to provide to the publics. BPA should not be selling the publics market based Tier 2 power, especially for new contracted for/committed to loads, when BPA allegedly has "surplus" cost-based power available to sell to the DSIs.

PLPT10005 at 2. BPA disagrees and has not made a finding of insufficient power. BPA dealt with DSI-related tiered rates issues comprehensively in the record of decision supporting BPA's Tiered Rate Methodology. Administrator's Record of Decision, Tiered Rate Methodology Rate Case, TRM-12-A-01 (November 2008) at 104-112. BPA also thoroughly dealt with the pricing of power service to preference customers at Tier 1 and Tier 2 PF rates in the record of decision supporting BPA's Tiered Rate Methodology. ICNU raises no new issues that were not discussed therein. The decision to offer a DSI contract is a determination that is unrelated to the Tiered Rate Methodology, which is applicable to public body and cooperative load. Moreover, as BPA earlier stated, "the TRM does not in any way remove or modify any ratesetting instructions contained in section 7 of the [Northwest Power Act], including section 7(c) regarding the IP rate, and the [Alcoa] Block Contract is explicit that all rate determinations will be made in BPA rate cases." Alcoa ROD at 18. Rate issues concerning DSI rates are the subject of BPA's current BP-12 power rate case, not the service decision in this ROD. Moreover, ICNU's argument is not with BPA's service to Port Townsend, but with the tiered rates construct embodied in the Tiered Rate Methodology. Legal challenges to the TRM have already been heard and decided by the Ninth Circuit Court of Appeals and are therefore outside the scope of this proceeding.

Nothwithstanding that, BPA will briefly address ICNU's concern here. To the extent that ICNU may have raised a new concern, the underlying premise of ICNU's argument is that BPA *should* not sell power to a DSI at the IP rate when it does not have enough power to sell to the preference customers at a cost-based rate. The use of the word "should" appears to indicate that ICNU is not contending BPA is legally prohibited from selling power to the DSIs but rather it is an unwise policy choice given their understanding of BPA's resources. ICNU's conclusion ignores the results of BPA's EBT analysis and is based on a flawed understanding of the nature of the rates charged to the DSIs, the allocation of BPA's resource costs, and the Tiered Rate Methodology.

ICNU contends that offering a contract to Port Townsend at "cost based rates" is inconsistent with separate determinations that BPA – again in ICNU's words – "has insufficient cost-based power to provide to the publics". The power offered to Port Townsend is being sold at the IP rate. The Northwest Power Act section 7(c) ties the IP rate to the rates BPA charges preference customers and the retail rates charged by them to their industrial customers. Section 7(c)'s primary directives are:

1. the IP rate shall be established at a level that the Administrator determines to be equitable in relation to the retail rates charged by BPA's public body and cooperative customers to their industrial customers;
2. that determination shall be based upon the Administrator's applicable wholesale rates to such public body and cooperative customers plus the "typical margins" included by such customers in their industrial rates; and
3. determining the level of the industrial margin requires BPA to take certain factors into consideration and directs BPA to account for the value of any reserves provided by the DSIs.

16 U.S.C. § 839e(c). The IP rate is also subject to surcharge, pursuant to section 7(b)(3), to recover costs that cannot be allocated to preference customers due to the protection afforded them by section 7(b)(2). 16 U.S.C. §§ 839e(b)(2) & 839e(b)(3). Along with certain adjustments, Congress chose to tie the IP rate to the rates charged preference customers, and that is just what BPA has proposed in its current rate case.

ICNU's next flawed assumption is that BPA has insufficient cost-based firm power to meet the need of its preference customers. Here ICNU appears to erroneously conflate the notion of offering power to the preference customers at Tier 2 rates with an inability to provide firm power for the net requirements of preference customers. The decision to tier the preference customer rates is a ratemaking construct. Under tiered rates BPA is allocating the costs of these specified Federal resources to preference customers, not the output of any particular resource. BPA continues to use the output of the entire Federal system resources to meet the firm loads of all of its customers.

Further, BPA has the obligation to meet preference customer service requests under section 5(b) of the Northwest Power Act, and the authority to acquire resources to meet those and other service requests under Northwest Power Act section 6. The rates for preference customer service are dictated by section 7(b) of the Northwest Power Act, and the Tiered Rate Methodology was adopted to implement section 7(b), utilizing the rate design discretion afforded the Administrator by section 7(e). Tier 1 rates and Tier 2 rates together recover the costs that BPA is authorized to recover from preference customers under section 7(b). In addition, if there is power that is available to preferences customers for sale at the Tier 1 rate, but the customers' requirements at those rates is less than what is available, preference customers' Tier 1 rates are credited with the revenues resulting from the sale of the power that could have been sold at Tier 1 rates but was instead sold at Tier 2 or other rates. A preference customer buying power at Tier 2 rates would face the same price signal whether or not BPA elected to serve Port Townsend or any other DSI customer.

Lastly, ICNU contends that BPA should not be selling "surplus" energy to the DSIs when it is selling Tier 2 power to the publics. Again, ICNU conflates and confuses the distinction between the allocation of cost associated with tiered rates and the sale of firm power to the DSIs. While it is unclear what ICNU means when it refers to surplus energy, the sales to the DSIs are firm power sales made from the Federal system resources. As to the contention BPA is selling Tier 2 power to the preference customers, there is no such thing as "Tier 2" power. As previously noted, the tiering of rates is a cost allocation methodology not an allocation of power. Preference customers purchasing under a CHWM Contract purchase requirements power products not Tier 1 or Tier 2 power. The rate or rates a particular customer pays depends upon the several factors that include among other things the customer's CHWM, power product choice and individual decisions about how it will meet any of its above HWM load.

In sum, BPA has developed the Equivalent Benefits Test as the means of determining whether it would be consistent with sound business principles to offer a DSI contract, as BPA currently understands the Ninth Circuit's opinions in *PNGC I* and *PNGC II*. BPA's decision to serve a DSI does not deprive a preference customer of the rate protections afforded it under section 7(b) of the Northwest Power Act. A preference customer buying power at Tier 2 rates would purchase the same amount of power at Tier 2 prices whether or not BPA elected to serve Port Townsend or any other DSI customer. Pricing of DSI service is under consideration in BPA's current rate case, and is a matter not dictated by the Tiered Rate Methodology. *Id.*

Decision: DSI service is not inconsistent with the Tiered Rate Methodology or the rate directives applicable to the IP rate.

d. Whether BPA has used the preservation of important, family wage jobs in the region as a justification for providing service to the Alcoa.

PNGC asserts that "BPA has justified selling power to serve the Intalco Works smelter on the grounds that it will preserve important, family-wage jobs . . . ." DCPT10008 at 2. While BPA maintains that service to Alcoa is outside the scope of this public comment process because it does not pertain to BPA's EBT determination for service to Port Townsend or to the terms of the proposed 2011 Contract, PNGC's assetion is inaccurate with respect to BPA's legal justification for providing service to the DSI's.

Prior to the adoption of the EBT methodology, jobs were a major factor in BPA's decisions to serve DSIs as evidenced by the 2006 *Regional Employment and Economic Study*. In *PNGC I* and *II,* the Court determined that BPA's business analysis must focus on its own business interest and not the business interests of its customers. Thus, according to the Court's opinions, BPA's jobs analysis was inappropriate. BPA believes this finding is unfortunate, but it has adhered to that standard, as it is required to do. The EBT methodology now used to determine whether providing service to the DSIs is "consistent with sound business principles" does not take jobs into account. Thus, BPA categorically does not take into consideration important regional jobs when determining whether it would be consistent with sound business principles to offer a DSI contract.

That fact, however, does not mean that any and all discussion of regional jobs is totally foreclosed. In the Alcoa ROD, the Administrator did discuss the potential for net positive employment. See Alcoa ROD at 94-101. BPA had received several comments from U.S. Senators, Representatives, and the Governor of Washington, and from large numbers of DSI employees, all of which dealt with the issue of retaining and preserving DSI jobs. BPA does not believe that it was in any way inappropriate to respond to those comments, and to the contrary, BPA believes that, as a public agency, it would have been remiss not to respond. That does not mean, however, that jobs were a factor in determining whether it would be consistent with the Ninth Circuit's view of when it would be in BPA's business interests to offer a power sales contract to the DSIs.

Decision: BPA has not relied upon the preservation of important, family wage jobs in the region as its legal justification for providing service to Alcoa or any other DSI since the implementation of the EBT. However, retention of family wage jobs otherwise remain an important consideration, particularly in light of current economic conditions. .

e. Whether the EBT Addresses Risks

PPC makes the general comment that BPA "makes no effort to determine what risks BPA is incurring in making that sale." DCPT10007. This is untrue. BPA has ensured that risks are addressed in the EBT methodology, and BPA has specifically addressed the market price risk and curtailment risk in prior RODs on DSI service and does so again below.[27] In addition, the 2011 Contract, as described above, contains risk mitigation provisions (i.e., take-or-pay obligation in section 4 of the 2011 Contract and associated payment obligations in Exhibit C of the 2011 Cotnract). BPA further notes that the risks associated with a sale of only 20.5 aMW of firm power for just over 2 years that generates approximately $14 million in cumulative revenues are not great when compared to BPA's nearly $6 billion Projected Revenues in the 2-year period from Proposed Rates in the BP-12 rate proceeding. See Table 2 in section III of this ROD and BPA's Power Revenue Requirement Study (BP-12-E-BPA-02) at 32.

BPA agrees with the assertion made by the PPC that the risk associated with the 2011 Contract is "dramatically less" than the risk associated with the provision of firm power service to Alcoa's Intalco Works because the 20.5 aMW level of firm power service to Port Townsend in the 2011 Contract is dramatically less than the 320 aMW of firm power service to Alcoa. DCPT10008 at 2. Said another way, Alcoa's invoice for firm power service at the IP rate is more in a single month than Port Townsend's invoice for firm power service at the IP rate for an entire year or more. Port Townsend's projected IP revenues for FY 2012 are only 6.6% of Alcoa's projected IP revenues for a similar period.[28]

Nonetheless, consistent with the Alcoa ROD, BPA also continues to believe that, despite being comparatively small, there are two primary elements of risk in this determination to offer the 2011 Contract to Port Townsend. The first is the risk of market prices for electricity deviating from the market prices forecast by BPA during the term of the 2011 Contract. The second primary element of risk is the possibility of Port Townsend curtailing during the term of the 2011 Contract. These risks are addressed further below and BPA continues to believe its risks, of which service to Port Townsend is a part, are prudently managed through BPA's operational conduct and rate proceedings. See generally Risk Analysis and Mitigation Study and Documentation, WP-10-FS-BPA-04 and 04A; and Power Risk and Market Price Study and Documentation, BP-12-E-BPA-04 and 04A.

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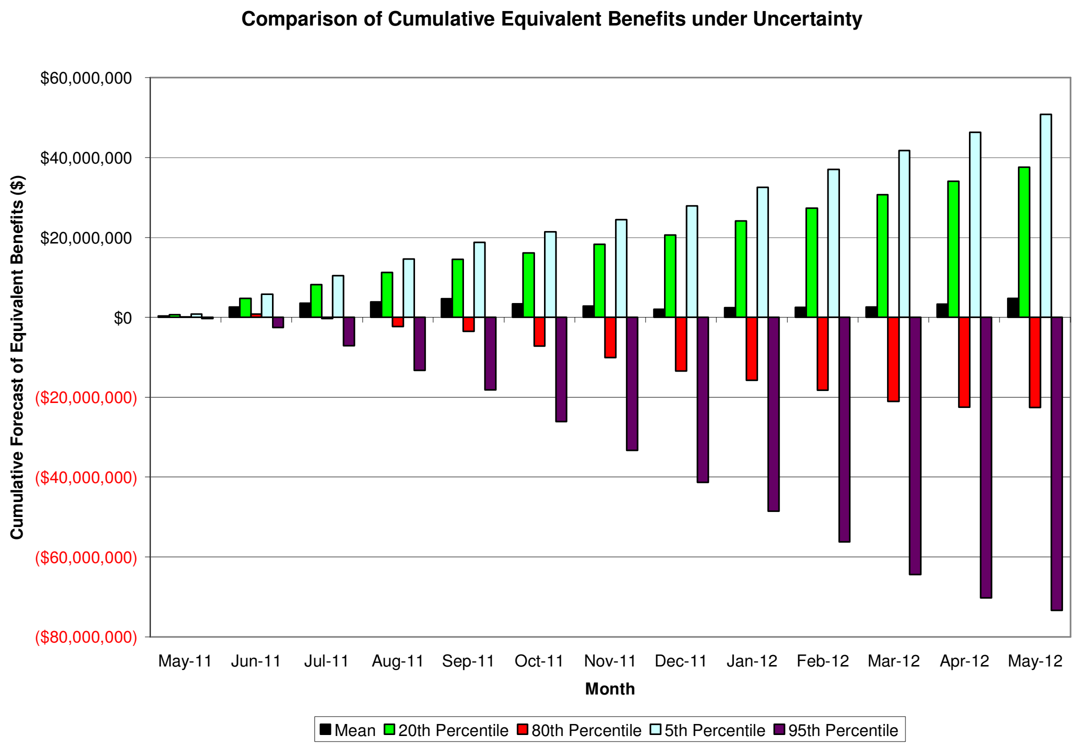
[27] See Alcoa ROD at 60-65; Port Townsend ROD at 27*; Administrator's Record of Decision Granting Alcoa's Request to Extend the Initial Period of Alcoa's Power Sales Agreement*, *Contract No. 10PB-12175,* October 29, 2010, at 34-36.

[28] The projected IP revenues for a full month of firm power service to Alcoa's Intalco smelter ranged from a low of $6,838,733 in June of 2011 to a high of $9,099,059 in January of 2012 (the months of May 2011 and May 2012 were both lower but firm power service was provided for only a portion of the days in either calendar month) and total $97,250,246 for the 12-month period. *See* Alcoa Extension ROD at 8. The projected IP revenues for a full year of firm power service to Port Townsend are $6,403,945 for FY 2012, or 6.6% of $97,250,246. *See* Section III of this Record of Decision.

Market Price Risk

BPA examined the period of the 2011 Contract both in isolation and more broadly in consideration of BPA's other risk factors. In examining the period of the 2011 Contract and the effects on the EBT in isolation, BPA applied the full probability distribution of forecast market prices to arrive at the net benefits for specific percentiles in that distribution.

Figure 5: Comparison of Cumulative Equivalent Benefits under Uncertainty



If market prices for electricity are less than expected, BPA is better off financially serving Port Townsend during the 2011 Contract than selling this power on the wholesale electricity market. This is reflected in Figure 5 for the 5th and 20th percentiles. Conversely, if market prices for electricity are higher than expected during the 2011 Contract, the outcome of this EBT changes such that BPA would be relatively worse off by offering the contract with Port Townsend relative to a market sale. This is reflected in Figure 5 above for the 80th and 95th percentiles. These results in isolation, however, do not reflect the impact of this transaction on BPA's overall probability distribution of net revenues, which among other things, takes into account conditions in which a loss from a DSI sale under higher prices than forecast can be associated with higher surplus energy revenues for other surplus power sales.

Regarding the financial risk that market prices deviate from the average of BPA's price forecast more broadly, BPA has analyzed the probability distribution of its net revenue risk consistent with the methodology used in both the WP-10 and BP-12 rate proceedings. See WP-10-FS-BPA-04 at 34, WP-10-FS-BPA-04B at 82, BP-12-E-BPA-

04 at 91, and BP-12-E-BPA-04A at 52. The advantage of this broader approach is that it takes into consideration the net revenue impacts to BPA in conjunction with all the other Operating and Non-Operating Risk Factors addressed in the WP-10 and BP-12 rate proceedings. See generally WP-10-FS-BPA-04 and BP-12-E-BPA-04. Our conclusion remains unchanged from the Alcoa ROD in that the probability distributions of BPA's net revenues, one of BPA's broadest measures of financial impact, are not materially different whether it serves or does not serve 20.5 aMW of DSI load during the 2011 Contract.[29] Therefore, contrary to the assertion of PPC, BPA is *not* "exposing its customers to the risk of higher power prices" in a material way as a result of the 2011 Contract. DCPT10007 at 2.

Curtailment Risk

Regarding the risk of curtailment, BPA does not expect Port Townsend will curtail its paper mill once 20.5 aMW of service is made available to it at the IP rate under the 2011 Contract. Port Townsend has indicated as recently as March 18, 2011 in another public comment process that it "…needs a reliable and economic 20.5 MW power supply to operate." (See Attachment E - Comments of Eveleen Muehlethaler, Vice President, Port Townsend Paper Company, March 18, 2011 at 1) BPA believes the 2011 Contract, albeit relatively short-term in nature, does provide "reliable and economic 20.5 MW power supply" and as such BPA expects Port Townsend will continue to operate its paper mill.

***Decision**:* BPA has adequately addressed the risks associated with the 2011 Contract. BPA has prudently accounted for, and expects to continue prudently accounting for, forecasted costs and risks associated with DSI service in setting its rates and has determined that it can reasonably expect to achieve Equivalent Benefits from the 2011 Contract. Simply put, the residual risk that BPA may incur costs to serve Port Townsend and that those costs result in an increase to the rates paid by preference customers is very small, and if it were to materialize, would likely result in no, or a negligible, increase in rates to preference customers.

f. Whether BPA has provided complete information

SUB commented that BPA has not provided sufficient information about the EBT. DCPT10006 at 5. Specifically, SUB notes that it does not have access to AURORA (a proprietary energy market model used by BPA) and cannot verify BPA's results. *Id.*

BPA has not withheld information. In the absence of a specific example of information that SUB believes has been withheld, BPA cannot respond to SUB's vague allegations that information has been withheld. SUB states that BPA has provided "insufficient information regarding Avoided Transmission and Ancillary Services Expenses to adequately provide comment on this issue." *Id.* BPA has provided all the information that it considered in the EBT analysis, either in this ROD or in the cited rate case materials. SUB further states that it does not have access to AURORA. *Id.* It is true that AURORA

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[29] *See* Alcoa ROD at 62.

is proprietary software and therefore BPA is restricted by the terms of its license. BPA does not believe that a party's professed inability to access the AURORA model means that BPA's analysis is "unsupported," or that BPA has improperly withheld information. SUB provides no basis upon which to conclude that use of the AURORA model is inappropriate or that the model itself is inherently flawed. Nor does SUB suggest an alternative approach or model that would perform the same function as the AURORA model, as effectively as the AURORA model, and which, at the same time, would be immediately accessible to all interested parties.

Decision*:* BPA has provided complete information.

g. Whether the Demand Shift Impacts Tier II Purchases

SUB reiterated their October 21, 2010, comment submitted in regard to an extension of service under Alcoa's block contract, stating that:

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

DCPT10006 at 2.

SUB's assertions are incorrect. First, the demand shift analysis used in each EBT evaluation accounts for BPA's balancing purchases and sales, and the forecast price impacts on them both, in the same manner described in the Alcoa ROD: "The demand shift analysis used both the surplus and deficit energy values to account for the impact of surplus energy sales and balancing power purchases in the computations." See Alcoa ROD at 48. Put another way, the demand shift benefit consists of the revenue which BPA forecasts to accrue from surplus sales less the amount that BPA expects to spend on balancing purchases. Therefore, any increase in the costs of balancing purchases is accounted for in the demand shift analysis.

SUB cited a list of rates for which the market price run is used from BPA's Power Rates Study (BP-12-E-BPA-01) that it claims are impacted by the demand shift:

(a) Prices for surplus energy sales and balancing power purchases in RAM2010,
(b) Load Shaping rate,
(c) Load Shaping True-up rate,
(d) Resource Shaping rate,
(e) Resource Support Service rates,
(f) Shaping the Demand Rate,

(g) PF Tier 2 Balancing Credit,
(h) PF Unused Rate-period High-Water Mark (RHWM) Credit,
(i) Tier 1 PF Equivalent Rates,
(j) Melded PF Equivalent Rates,
(k) Balancing Augmentation Credit, and
(l) NR rate design.

See SUB, DCPT10006 at 3 quoting BP-12-E-BPA-14 at pages 3 &5.

However, these are *rates or cost pool adjustments* that are affected by the market price forecast since they are designed to send price signals or allocate forecast costs/credits to the parties causing the cost/credit. These rates and adjustments represent rate design, which by themselves do not change BPA's Revenue Requirement but rather how BPA's Revenue Requirement is allocated across parties. In other words, rate design reflects the recovery of costs incurred or to be incurred, but does not cause costs/credits. The costs/credits incurred by BPA emanate from balancing purchases, secondary revenue, or augmentation purchases. These particular costs have been included in the demand shift computations.

Second, the demand shift has not affected the cost allocation to the Tier 2 rate applicable to Above High Water Mark load during the FY 2012-13 rate period. BPA purchased power to meets its obligation to supply 22 aMW of customer Above High Water Mark Load (Tier 2 purchase obligation) for FY 2012 and the 58 aMW of customer Above High Water Mark Load for FY 2013 in April and May 2010. These were purchases made at forward market prices prevailing well before Port Townsend's proposed draft contract was released on February 3, 2011. See BPA Bulk Hub Purchase Notification for Service at Tier 2 Rates, dated April 7, 2010, and May 25, 2010. The demand shift is BPA's forecast of the impact an assumed increment of DSI load will have on market-clearing prices for electricity at Mid-C. While forward market prices for future delivery are impacted by the market participants' view of what loads might be in the future, market participants, including BPA, did not know whether or not BPA's obligation to provide firm power to Port Townsend would be extended past May 31, 2011, in April and May 2010. Similarly, market participants did not know whether or not BPA's obligation to provide firm power to Alcoa would extend past May 26, 2011.[30] Therefore, prices for these Tier 2 purchases were not impacted by the demand shift used in BPA's determinations of Equivalent Benefits for the DSIs.

Lastly, with regard to SUB's allegation that the demand shift increases the costs to preference customers and therefore should not be considered a benefit to BPA, BPA notes that the EBT was designed to determine whether a given DSI sale is consistent with "sound business principles." DCPT10006 at 2-4. Generally speaking, a business does not take into account the impact on other market participants when determining whether to make a sale or purchase. Similarly, BPA does not consider direct costs to other parties in the EBT. This approach is in keeping with both BPA's understanding of *PNGC I* and *II*

[30] See generally *Administrator's Record of Decision Granting Alcoa's Request to Extend the Initial Period of Alcoa's Power Sales Agreement*, *Contract No. 10PB-12175,* October 29, 2010.

and preference customers' arguments, made in reliance on those two opinions, that BPA's actions with respect to DSI customers should be consistent with sound business principles. The Court also determined that BPA's business analysis must focus on its own business interest and not the business interests of its customers. SUB now seems to maintain that, on this particular issue at least, BPA's actions should be inconsistent with sound business principles. Following such a course, however, would be an unwarranted departure from BPA's view of the Ninth Circuit's current requirements for determining whether a DSI contract should be offered.

Decision: The demand shift is appropriately included as a benefit in the EBT analysis.

V. 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 D.

VI. CONCLUSION

Based on the above results of the Equivalent Benefits Test, BPA has signed the 2011 Contract on the date of this record of decision.

Issued at Portland, Oregon.

/s/ Stephen J. Wright____________ April 18, 2011______
Stephen J. Wright Date
Administrator and Chief Executive Officer

Point of Contract for this issue is Mark Miller, Account Executive, Bulk Marketing, 503-230-4003, memiller@bpa.gov or Jon Wright, Attorney, BPA General Counsel Office, 503-230-7596, jdwright@bpa.gov

Attachments to

20.5 aMW POWER SALE TO PORT TOWNSEND PAPER CORPORATION FOR THE PERIOD JUNE 1, 2011, THROUGH AUGUST 31, 2013

ADMINISTRATOR'S RECORD OF DECISION

April 18, 2011

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TABLE OF CONTENTS

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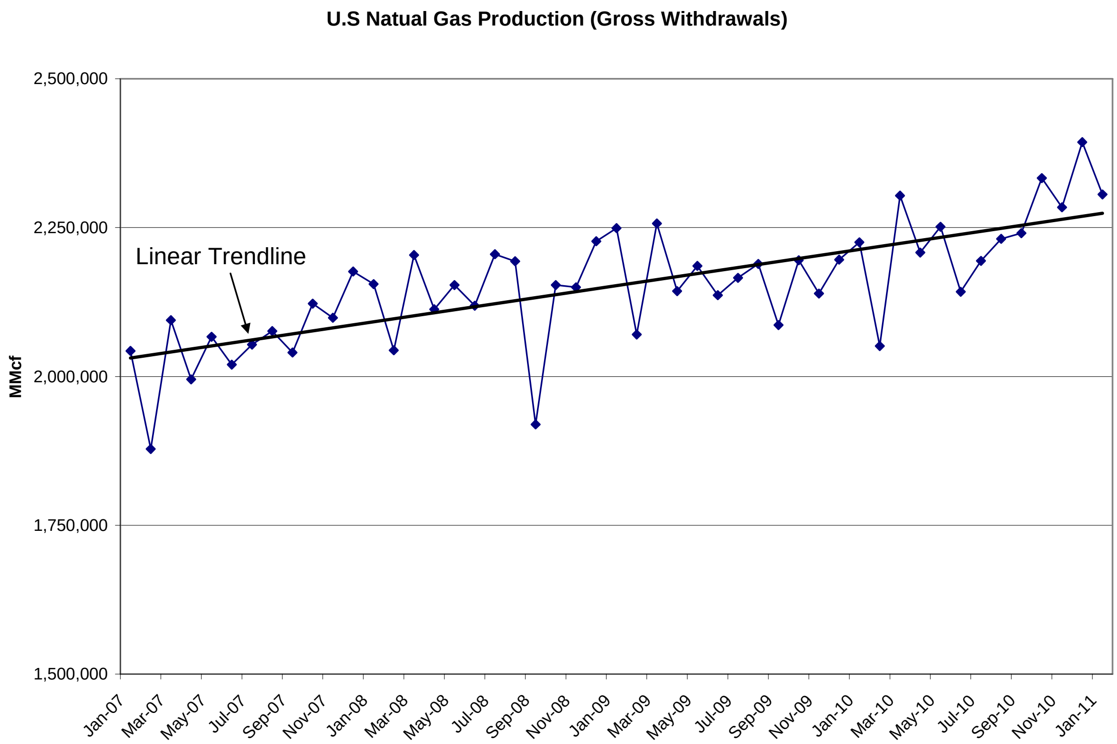
Attachment A

Natural Gas Statistics

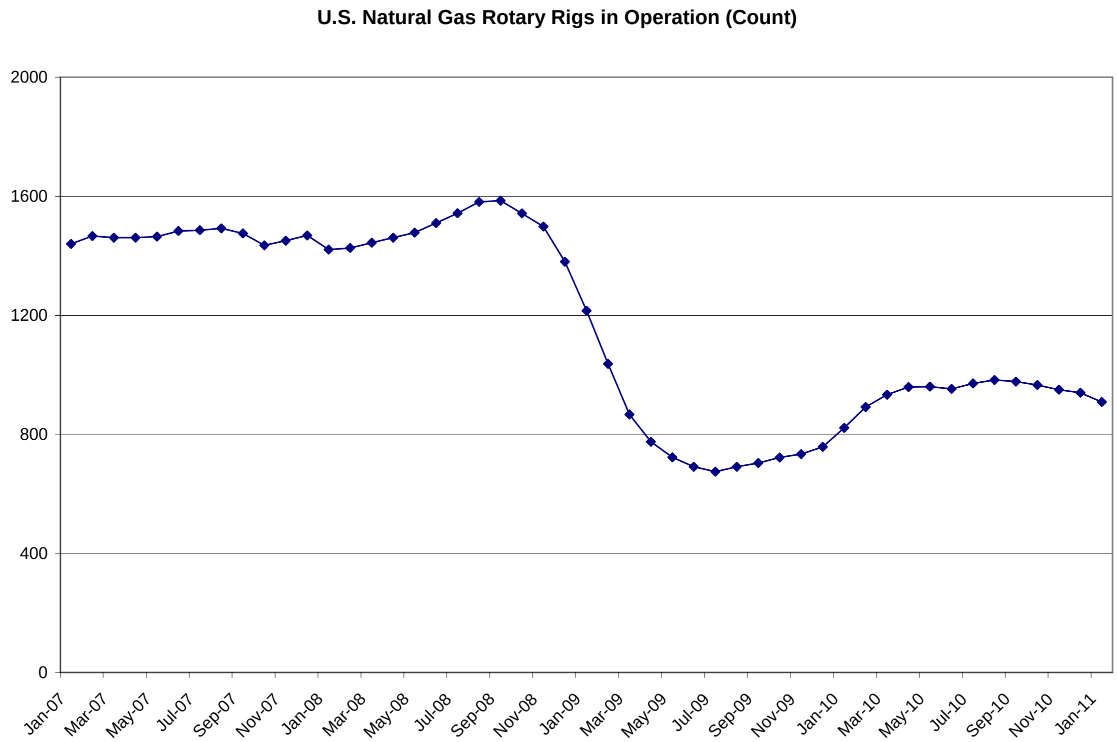
Natural Gas Statistics

Figure 1 – Natural Gas Production



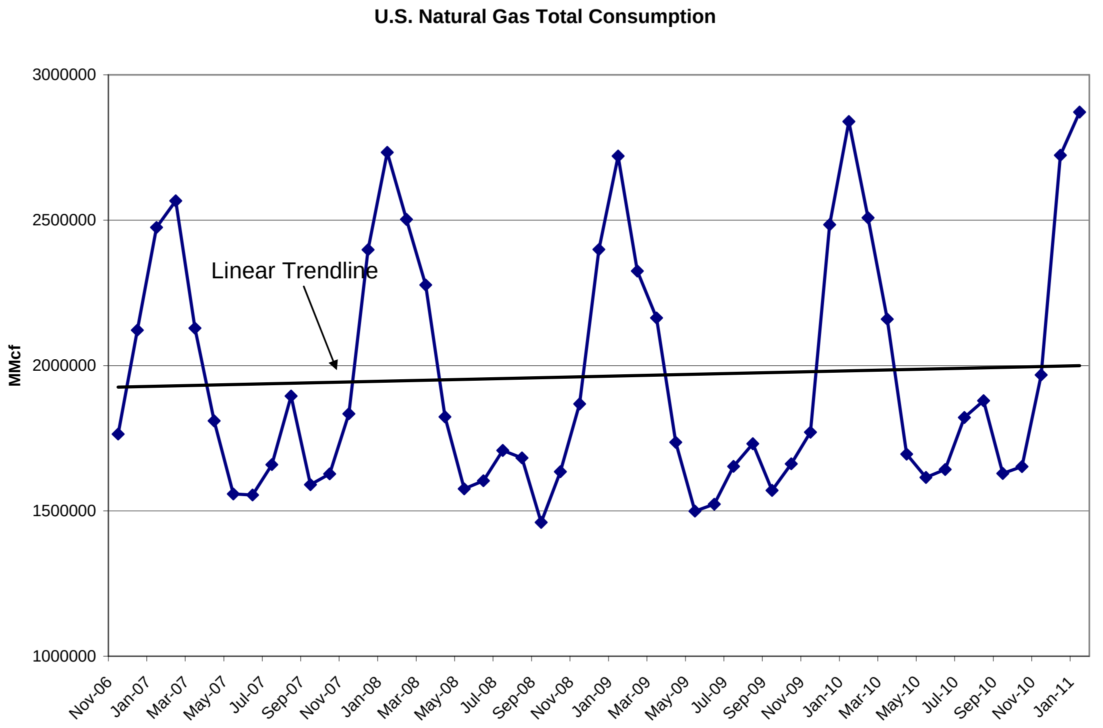
Source: United States Department of Energy, Energy Information Administration, March 29, 2011

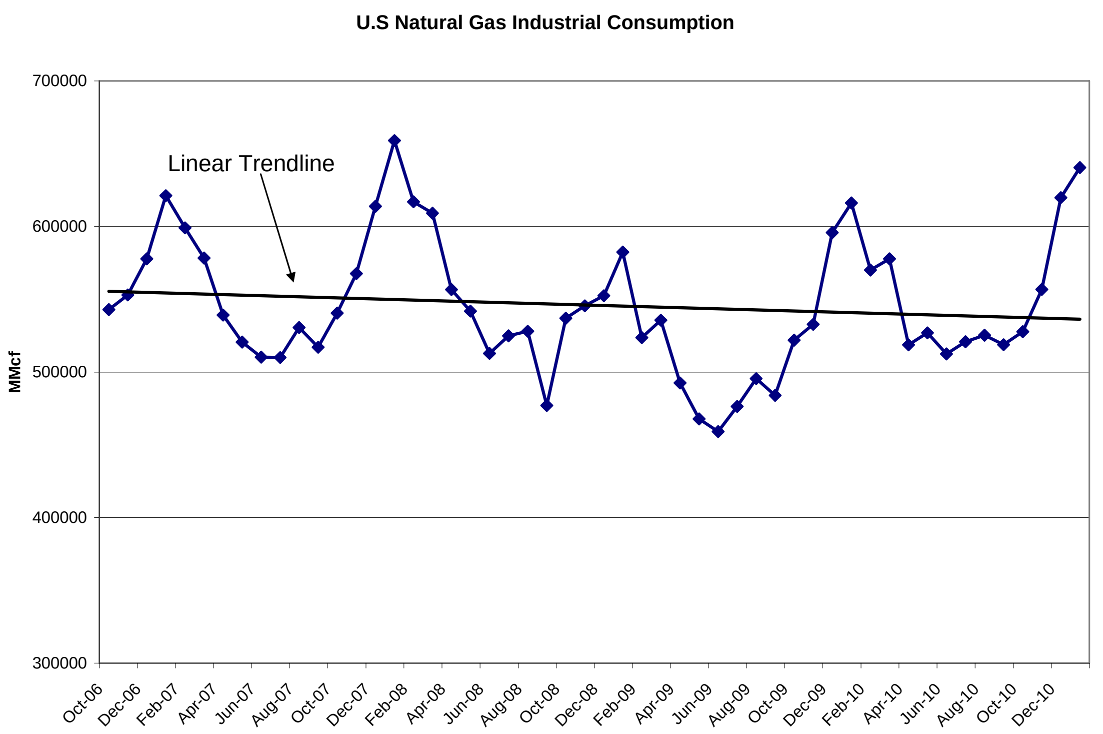
Figure 2 – Natural Gas Rig Count



Source: United States Department of Energy, Energy Information Administration, March 3, 2011.

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





Source: United States Department of Energy, Energy Information Administration, March 29, 2011.

Figure 4 – Natural Gas Storage

Weekly Natural Gas Storage Report

Release Schedule
Sign Up for Email Updates

Released: March 31, 2011 at 10:30 a.m. (eastern time) for the Week Ending March 25, 2011.
Next Release: April 7, 2011

Working Gas in Underground Storage, Lower 48 — other formats: Summary TXT CSV

Region	Stocks in billion cubic feet (Bcf)			Historical Comparisons			
	03/25/11	03/18/11	Change	Year Ago (03/25/10)		5-Year (2006-2010) Average	
				Stocks (Bcf)	% Change	Stocks (Bcf)	% Change
East	668	675	-7	754	-11.4	707	-5.5
West	216	222	-6	288	-25.0	242	-10.7
Producing	740	715	25	594	24.6	607	21.9
Total	**1,624**	**1,612**	**12**	**1,636**	**-0.7**	**1,556**	**4.4**

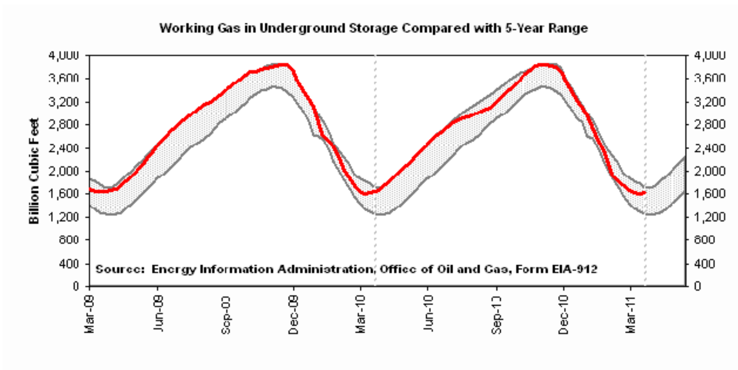
Notes and Definitions

Data
- History (XLS)
- 5-Year Averages, Maximum, Minimum, and Year-Ago Stocks (XLS)

References
- Methodology
- Differences Between Monthly and Weekly Data
- Revision Policy

Related Links
- Storage Basics
- Natural Gas Weekly Update
- Natural Gas Navigator

Summary
Working gas in storage was 1,624 Bcf as of Friday, March 25, 2011, according to EIA estimates. This represents a net increase of 12 Bcf from the previous week. Stocks were 12 Bcf less than last year at this time and 68 Bcf above the 5-year average of 1,556 Bcf. In the East Region, stocks were 39 Bcf below the 5-year average following net withdrawals of 7 Bcf. Stocks in the Producing Region were 133 Bcf above the 5-year average of 607 Bcf after a net injection of 25 Bcf. Stocks in the West Region were 26 Bcf below the 5-year average after a net drawdown of 6 Bcf. At 1,624 Bcf, total working gas is within the 5-year historical range.



Note: The shaded area indicates the range between the historical minimum and maximum values for the weekly series from 2006 through 2010.
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, March 31, 2011.

Attachment B

Alcoa EBT Analysis Beginning May 27, 2012

Alcoa EBT Analysis Beginning May 27, 2012

May 2012 energy and revenue amounts are for the period 5/27/12 through 5/30/12

Alcoa EBT Analysis

TABLE 1 - Usage and Rates

Month	Alcoa Usage			Projected IP Rates		
	Demand (kW)	HLH (MWh)	LLH (MWh)	Demand ($ / kW)	HLH ($ / MWh)	LLH ($ / MWh)
May-12	320,000	15,360	23,040	$8.15	$35.11	$19.85
Jun-12	320,000	133,120	97,280	$8.39	$36.27	$20.50
Jul-12	320,000	128,000	110,080	$10.55	$46.43	$33.34
Aug-12	320,000	138,240	99,840	$10.99	$48.48	$35.15
Sep-12	320,000	122,880	107,520	$10.38	$45.58	$31.83
Oct-12	320,000	138,240	99,840	$9.35	$40.74	$30.93
Nov-12	320,000	128,000	102,720	$9.46	$41.26	$30.71
Dec-12	320,000	128,000	110,080	$10.13	$44.40	$34.23
Jan-13	320,000	133,120	104,960	$9.74	$42.56	$31.50

TABLE 2 - BPA's Projected Revenue

Month	Revenues by Rate Determinant			Projected IP Revenue	
	Demand ($)	HLH ($)	LLH ($)	Month ($)	Cumulative ($)
May-12	$0	$539,290	$457,344	$996,634	$996,634
Jun-12	$0	$4,828,262	$1,994,240	$6,822,502	$7,819,136
Jul-12	$0	$5,943,040	$3,670,067	$9,613,107	$17,432,243
Aug-12	$0	$6,701,875	$3,509,376	$10,211,251	$27,643,494
Sep-12	$0	$5,600,870	$3,422,362	$9,023,232	$36,666,726
Oct-12	$0	$5,631,898	$3,088,051	$8,719,949	$45,386,675
Nov-12	$0	$5,281,280	$3,154,531	$8,435,811	$53,822,486
Dec-12	$0	$5,683,200	$3,768,038	$9,451,238	$63,273,725
Jan-13	$0	$5,665,587	$3,306,240	$8,971,827	$72,245,552

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

Month	Forecasted Market Price		Forecasted Revenues Obtained from the Market			
	HLH Price ($ / MWh)	LLH Price ($ / MWh)	HLH ($)	LLH ($)	Month ($) (HLH + LLH)	Cumulative ($)
May-12	$35.68	$21.17	$548,045	$487,757	$1,035,802	$1,035,802
Jun-12	$37.13	$22.24	$4,942,746	$2,163,507	$7,106,253	$8,142,054
Jul-12	$47.37	$34.84	$6,063,360	$3,835,187	$9,898,547	$18,040,602
Aug-12	$49.32	$36.61	$6,817,997	$3,655,142	$10,473,139	$28,513,741
Sep-12	$46.26	$33.16	$5,684,429	$3,565,363	$9,249,792	$37,763,533
Oct-12	$46.49	$35.68	$6,426,778	$3,562,291	$9,989,069	$47,752,602
Nov-12	$46.53	$34.65	$5,955,840	$3,559,248	$9,515,088	$57,267,690
Dec-12	$49.50	$38.40	$6,336,000	$4,227,072	$10,563,072	$67,830,762
Jan-13	$48.97	$37.11	$6,518,886	$3,895,066	$10,413,952	$78,244,714

TABLE 4 - BPA's Net Benefit before Adjustment

Month	Net Revenue or (Cost) Month ($)	Net Revenue or (Cost) Cumulative ($)
May-12	($39,168)	($39,168)
Jun-12	($283,750)	($322,918)
Jul-12	($285,440)	($608,358)
Aug-12	($261,888)	($870,246)
Sep-12	($226,560)	($1,096,806)
Oct-12	($1,269,120)	($2,365,926)
Nov-12	($1,079,277)	($3,445,203)
Dec-12	($1,111,834)	($4,557,037)
Jan-13	($1,442,125)	($5,999,162)

TABLE 5a - BPA's Net Benefit Adjustments

Month	Value of Reserves Month ($)	Value of Reserves Cumulative ($)
May-12	$36,480	$36,480
Jun-12	$218,880	$255,360
Jul-12	$226,176	$481,536
Aug-12	$226,176	$707,712
Sep-12	$218,880	$926,592
Oct-12	$226,176	$1,152,768
Nov-12	$219,184	$1,371,952
Dec-12	$226,176	$1,598,128
Jan-13	$226,176	$1,824,304

TABLE 5b - BPA's Net Benefit Adjustments

Month	Avoided Tx and Ancillary Service Costs Month ($)	Proportional Month ($)	Cumulative ($)
May-12	$101,806	$95,817	$95,817
Jun-12	$524,069	$493,241	$589,058
Jul-12	$246,818	$232,299	$821,357
Aug-12	$43,497	$40,939	$862,296
Sep-12	$20,371	$19,173	$881,469
Oct-12	$12,378	$11,650	$893,118
Nov-12	$32,792	$30,863	$923,982
Dec-12	$77,506	$72,947	$996,929
Jan-13	$267,721	$251,972	$1,248,901

TABLE 5c - BPA's Net Benefit Adjustments

Month	Demand Shift Month ($)	Proportional Month ($)	Cumulative ($)
May-12	$200,734	$188,926	$188,926
Jun-12	$1,174,751	$1,105,648	$1,294,573
Jul-12	$533,197	$501,832	$1,796,406
Aug-12	$103,935	$97,821	$1,894,227
Sep-12	$61,947	$58,303	$1,952,530
Oct-12	($45,776)	($43,083)	$1,909,447
Nov-12	$103,379	$97,298	$2,006,744
Dec-12	$110,588	$104,083	$2,110,827
Jan-13	$407,165	$383,215	$2,494,042

TABLE 6 - BPA's Net Benefit after Adjustments

BPA's Adjusted Net Revenue or (Cost) (May Cumilative reflects beginning May 27)

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 ($)	Cumulative ($)
May-12	($39,168)	$36,480	$95,817	$188,926	$282,055	$282,055
Jun-12	($283,750)	$218,880	$493,241	$1,105,648	$1,534,019	$1,816,073
Jul-12	($285,440)	$226,176	$232,299	$501,832	$674,867	$2,490,940
Aug-12	($261,888)	$226,176	$40,939	$97,821	$103,048	$2,593,988
Sep-12	($226,560)	$218,880	$19,173	$58,303	$69,796	$2,663,784
Oct-12	($1,269,120)	$226,176	$11,650	($43,083)	($1,074,377)	$1,589,406
Nov-12	($1,079,277)	$219,184	$30,863	$97,298	($731,932)	$857,475
Dec-12	($1,111,834)	$226,176	$72,947	$104,083	($708,628)	$148,847
Jan-13	($1,442,125)	$226,176	$251,972	$383,215	($580,762)	($431,915)

Attachment C

Port Townsend EBT Analysis with Avoided Transmission and Ancillary Services Cost and Demand Shift Benefits through May 26, 2012

Port Townsend EBT Analysis with Avoided Transmission and Ancillary Services Cost and Demand Shift Benefits through May 26, 2012

Port Townsend EBT Analysis
TABLE 1 - Usage and Rates

Month	Port Townsend Usage			Projected IP Rates		
	Demand (kW)	HLH (MWh)	LLH (MWh)	Demand ($ / kW)	HLH ($ / MWh)	LLH ($ / MWh)
Jun-11	20,000	8,320	6,080	$1.32	$31.18	$23.29
Jul-11	20,000	8,000	6,880	$1.61	$33.33	$28.66
Aug-11	20,000	8,640	6,240	$1.89	$37.31	$31.40
Sep-11	20,000	8,000	6,400	$1.96	$36.49	$32.26
Oct-11	20,000	8,320	6,560	$9.35	$40.74	$30.93
Nov-11	20,000	8,000	6,420	$9.46	$41.26	$30.71
Dec-11	20,000	8,320	6,560	$10.13	$44.40	$34.23
Jan-12	20,000	8,000	6,880	$9.74	$42.56	$31.50
Feb-12	20,000	8,000	5,920	$9.75	$42.65	$31.64
Mar-12	20,000	8,640	6,220	$9.36	$40.78	$29.71
Apr-12	20,000	8,000	6,400	$8.57	$37.06	$26.54
May-12	20,000	8,320	6,560	$8.15	$35.11	$19.85
Jun-12	20,000	8,320	6,080	$8.39	$36.27	$20.50
Jul-12	20,000	8,000	6,880	$10.55	$46.43	$33.34
Aug-12	20,000	8,640	6,240	$10.99	$48.48	$35.15
Sep-12	20,000	7,680	6,720	$10.38	$45.58	$31.83
Oct-12	20,000	8,640	6,240	$9.35	$40.74	$30.93
Nov-12	20,000	8,000	6,420	$9.46	$41.26	$30.71
Dec-12	20,000	8,000	6,880	$10.13	$44.40	$34.23
Jan-13	20,000	8,320	6,560	$9.74	$42.56	$31.50
Feb-13	20,000	7,680	5,760	$9.75	$42.65	$31.64
Mar-13	20,000	8,320	6,540	$9.36	$40.78	$29.71
Apr-13	20,000	8,320	6,080	$8.57	$37.06	$26.54
May-13	20,000	8,320	6,560	$8.15	$35.11	$19.85
Jun-13	20,000	8,000	6,400	$8.39	$36.27	$20.50

TABLE 2 - BPA's Projected Revenue

Month	Revenues by Rate Determinant			Projected IP Revenue	
	Demand ($)	HLH ($)	LLH ($)	Month ($)	Cumulative ($)
Jun-11	$26,400	$259,418	$141,603	$427,421	$427,421
Jul-11	$32,200	$266,640	$197,181	$496,021	$923,442
Aug-11	$37,800	$322,358	$195,936	$556,094	$1,479,536
Sep-11	$39,200	$291,920	$206,464	$537,584	$2,017,120
Oct-11	$0	$338,957	$202,901	$541,858	$2,558,978
Nov-11	$0	$330,080	$197,158	$527,238	$3,086,216
Dec-11	$0	$369,408	$224,549	$593,957	$3,680,173
Jan-12	$0	$340,480	$216,720	$557,200	$4,237,373
Feb-12	$0	$341,200	$187,309	$528,509	$4,765,881
Mar-12	$0	$352,339	$184,796	$537,135	$5,303,017
Apr-12	$0	$296,480	$169,856	$466,336	$5,769,353
May-12	$0	$292,115	$130,216	$422,331	$6,191,684
Jun-12	$0	$301,766	$124,640	$426,406	$6,618,090
Jul-12	$0	$371,440	$229,379	$600,819	$7,218,910
Aug-12	$0	$418,867	$219,336	$638,203	$7,857,113
Sep-12	$0	$350,054	$213,898	$563,952	$8,421,065
Oct-12	$0	$351,994	$193,003	$544,997	$8,966,062
Nov-12	$0	$330,080	$197,158	$527,238	$9,493,300
Dec-12	$0	$355,200	$235,502	$590,702	$10,084,002
Jan-13	$0	$354,099	$206,640	$560,739	$10,644,741
Feb-13	$0	$327,552	$182,246	$509,798	$11,154,540
Mar-13	$0	$339,290	$194,303	$533,593	$11,688,133
Apr-13	$0	$308,339	$161,363	$469,702	$12,157,835
May-13	$0	$292,115	$130,216	$422,331	$12,580,166
Jun-13	$0	$290,160	$131,200	$421,360	$13,001,526

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 ($) (HLH + LLH)	Cumulative ($)
Jun-11	$30.17	$22.73	$250,981	$138,205	$389,186	$389,186
Jul-11	$32.67	$25.56	$261,330	$175,841	$437,171	$826,357
Aug-11	$36.24	$28.63	$313,074	$178,631	$491,706	$1,318,063
Sep-11	$34.20	$27.78	$273,575	$177,807	$451,382	$1,769,445
Oct-11	$41.44	$32.61	$344,781	$213,922	$558,702	$2,328,147
Nov-11	$42.43	$33.22	$339,440	$213,272	$552,712	$2,880,860
Dec-11	$45.75	$36.51	$380,640	$239,506	$620,146	$3,501,005
Jan-12	$42.59	$32.33	$340,720	$222,430	$563,150	$4,064,156
Feb-12	$42.12	$32.07	$336,960	$189,854	$526,814	$4,590,970
Mar-12	$40.73	$30.73	$351,907	$191,141	$543,048	$5,134,018
Apr-12	$36.94	$26.35	$295,520	$168,640	$464,160	$5,598,178
May-12	$35.68	$21.17	$296,858	$138,875	$435,733	$6,033,911
Jun-12	$37.13	$22.24	$308,922	$135,219	$444,141	$6,478,051
Jul-12	$47.37	$34.84	$378,960	$239,699	$618,659	$7,096,711
Aug-12	$49.32	$36.61	$426,125	$228,446	$654,571	$7,751,282
Sep-12	$46.26	$33.16	$355,277	$222,835	$578,112	$8,329,394
Oct-12	$46.49	$35.68	$401,674	$222,643	$624,317	$8,953,711
Nov-12	$46.53	$34.65	$372,240	$222,453	$594,693	$9,548,404
Dec-12	$49.50	$38.40	$396,000	$264,192	$660,192	$10,208,596
Jan-13	$48.97	$37.11	$407,430	$243,442	$650,872	$10,859,468
Feb-13	$49.61	$37.64	$381,005	$216,806	$597,811	$11,457,279
Mar-13	$47.28	$35.13	$393,370	$229,750	$623,120	$12,080,399
Apr-13	$43.61	$33.17	$362,835	$201,674	$564,509	$12,644,907
May-13	$40.98	$24.97	$340,954	$163,803	$504,757	$13,149,664
Jun-13	$41.86	$25.19	$334,880	$161,216	$496,096	$13,645,760

TABLE 4 - BPA's Net Benefit before Adjustment

Month	Net Revenue or (Cost) Month ($)	Cumulative ($)
Jun-11	$38,235	$38,235
Jul-11	$58,850	$97,085
Aug-11	$64,389	$161,473
Sep-11	$86,202	$247,675
Oct-11	($16,845)	$230,830
Nov-11	($25,474)	$205,356
Dec-11	($26,189)	$179,167
Jan-12	($5,950)	$173,217
Feb-12	$1,694	$174,911
Mar-12	($5,912)	$168,999
Apr-12	$2,176	$171,175
May-12	($13,402)	$157,773
Jun-12	($17,734)	$140,039
Jul-12	($17,840)	$122,199
Aug-12	($16,368)	$105,831
Sep-12	($14,160)	$91,671
Oct-12	($79,320)	$12,351
Nov-12	($67,455)	($55,104)
Dec-12	($69,490)	($124,593)
Jan-13	($90,133)	($214,726)
Feb-13	($88,013)	($302,739)
Mar-13	($89,527)	($392,266)
Apr-13	($94,806)	($487,072)
May-13	($82,426)	($569,498)
Jun-13	($74,736)	($644,234)

TABLE 5a - BPA's Net Benefit Adjustments

Month	Value of Reserves Month ($)	Cumulative ($)
Jun-11	$11,520	$11,520
Jul-11	$11,904	$23,424
Aug-11	$11,904	$35,328
Sep-11	$11,520	$46,848
Oct-11	$14,136	$60,984
Nov-11	$13,699	$74,683
Dec-11	$14,136	$88,819
Jan-12	$14,136	$102,955
Feb-12	$13,224	$116,179
Mar-12	$14,117	$130,296
Apr-12	$13,680	$143,976
May-12	$14,136	$158,112
Jun-12	$13,680	$171,792
Jul-12	$14,136	$185,928
Aug-12	$14,136	$200,064
Sep-12	$13,680	$213,744
Oct-12	$14,136	$227,880
Nov-12	$13,699	$241,579
Dec-12	$14,136	$255,715
Jan-13	$14,136	$269,851
Feb-13	$12,768	$282,619
Mar-13	$14,117	$296,736
Apr-13	$13,680	$310,416
May-13	$14,136	$324,552
Jun-13	$13,680	$338,232

TABLE 5b - BPA's Net Benefit Adjustments

Avoided Tx and Ancillary Service Costs (May-12 is through May 26)

Month	Month ($)	Proportional Month ($)	Cumulative ($)
Jun-11	$277,342	$16,314	$16,314
Jul-11	$85,751	$5,044	$21,358
Aug-11	$0	$0	$21,358
Sep-11	$0	$0	$21,358
Oct-11	$8,526	$502	$21,860
Nov-11	$22,634	$1,331	$23,191
Dec-11	$70,298	$4,135	$27,327
Jan-12	$275,908	$16,230	$43,556
Feb-12	$229,707	$13,512	$57,069
Mar-12	$238,162	$14,010	$71,078
Apr-12	$406,871	$23,934	$95,012
May-12	$529,389	$31,141	$126,152
Jun-12		$0	$126,152
Jul-12		$0	$126,152
Aug-12		$0	$126,152
Sep-12		$0	$126,152
Oct-12		$0	$126,152
Nov-12		$0	$126,152
Dec-12		$0	$126,152
Jan-13	$0	$0	$126,152
Feb-13	$0	$0	$126,152
Mar-13	$0	$0	$126,152
Apr-13	$0	$0	$126,152
May-13	$0	$0	$126,152
Jun-13	$0	$0	$126,152

The May-12 Proportional Month is the amount of benefit for May 1 through May 26.

TABLE 5c - BPA's Net Benefit Adjustments

Month	**Demand Shift** (May-12 is through May 26) Month ($)	Proportional Month ($)	Cumulative ($)
Jun-11	$231,819	$13,636	$13,636
Jul-11	$59,053	$3,474	$17,110
Aug-11	($170,339)	($10,020)	$7,090
Sep-11	($79,296)	($4,664)	$2,426
Oct-11	($58,137)	($3,420)	($994)
Nov-11	$32,607	$1,918	$924
Dec-11	$32,513	$1,913	$2,836
Jan-12	$389,460	$22,909	$25,746
Feb-12	$340,733	$20,043	$45,789
Mar-12	$481,712	$28,336	$74,125
Apr-12	$571,432	$33,614	$107,739
May-12	$1,043,814	$61,401	$169,139
Jun-12		$0	$169,139
Jul-12		$0	$169,139
Aug-12		$0	$169,139
Sep-12		$0	$169,139
Oct-12		$0	$169,139
Nov-12		$0	$169,139
Dec-12		$0	$169,139
Jan-13	$0	$0	$169,139
Feb-13	$0	$0	$169,139
Mar-13	$0	$0	$169,139
Apr-13	$0	$0	$169,139
May-13	$0	$0	$169,139
Jun-13	$0	$0	$169,139

The May-12 Proportional Month is the amount of benefit for May 1 through May 26.

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)					
Jun-11	$38,235	$11,520	$16,314	$13,636	$79,705	$79,705
Jul-11	$58,850	$11,904	$5,044	$3,474	$79,272	$158,977
Aug-11	$64,389	$11,904	$0	($10,020)	$66,273	$225,250
Sep-11	$86,202	$11,520	$0	($4,664)	$93,057	$318,307
Oct-11	($16,845)	$14,136	$502	($3,420)	($5,627)	$312,680
Nov-11	($25,474)	$13,699	$1,331	$1,918	($8,526)	$304,154
Dec-11	($26,189)	$14,136	$4,135	$1,913	($6,005)	$298,149
Jan-12	($5,950)	$14,136	$16,230	$22,909	$47,325	$345,474
Feb-12	$1,694	$13,224	$13,512	$20,043	$48,474	$393,948
Mar-12	($5,912)	$14,117	$14,010	$28,336	$50,550	$444,498
Apr-12	$2,176	$13,680	$23,934	$33,614	$73,403	$517,901
May-12 *	($13,402)	$14,136	$31,141	$61,401	$93,276	$611,177
Jun-12	($17,734)	$13,680	$0	$0	($4,054)	$607,123
Jul-12	($17,840)	$14,136	$0	$0	($3,704)	$603,419
Aug-12	($16,368)	$14,136	$0	$0	($2,232)	$601,187
Sep-12	($14,160)	$13,680	$0	$0	($480)	$600,707
Oct-12	($79,320)	$14,136	$0	$0	($65,184)	$535,523
Nov-12	($67,455)	$13,699	$0	$0	($53,756)	$481,767
Dec-12	($69,490)	$14,136	$0	$0	($55,354)	$426,413
Jan-13	($90,133)	$14,136	$0	$0	($75,997)	$350,416
Feb-13	($88,013)	$12,768	$0	$0	($75,245)	$275,172
Mar-13	($89,527)	$14,117	$0	$0	($75,410)	$199,762
Apr-13	($94,806)	$13,680	$0	$0	($81,126)	$118,635
May-13	($82,426)	$14,136	$0	$0	($68,290)	$50,346
Jun-13	($74,736)	$13,680	$0	$0	($61,056)	($10,710)

* The values for the month of May-12 for Net Revenue or (Cost) in column (A) and Value of Reserves in colunn (B) are now consistent with the values for May-12 displayed in Tables 4 and 5a from this Appendix. This causes the Cumulative total through May-13 displayed in Table 6 of this analysis to equal $50,346, as opposed to the $53,359 displayed in this portion of the draft determination.

Attachment D

BPA’s Record of Decision on Short-Term Marketing and Operating Arrangements

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

Attachment E

Comments of Eveleen Muehlethaler, Vice President, Port Townsend Paper Company,

March 18, 2011

COMMENTS OF EVELEEN MUEHLETHALER
VICE PRESIDENT
PORT TOWNSEND PAPER CORPORATION

MARCH 18, 2011

PORT TOWNSEND PAPER CORPORATION'S LOADS

My company, Port Townsend Paper Corporation ("PTPC"), owns and operates the Unbleached Kraft Pulp and Paper mill in Jefferson County Washington. We are the largest private employer in Jefferson County. We provide 300 family-wage jobs at our mill. In addition, we send an additional $125,000,000 into the neighboring area for the purchase of raw materials and other supplies, supporting hundreds of additional local jobs.

PTPC needs a reliable and economic 20.5 MW power supply to operate. Since 1947 it has purchased this power from Bonneville Power Administration ("BPA") as a direct service industrial ("DSI") customer. The BPA has found that it is serving two distinct PTPC loads, the 3.275 MW load for the newer Old Corrugated Cardboard, or OCC, recycle plant and the mill load (about 17 MW).

Today there exists a unique opportunity for the PTPC mill to become a customer of a newly formed BPA preference customer, Public Utility District No. 1 of Jefferson County Oregon ("JPUD"). JPUD expects to commence operations in 2013. PTPC is eligible for service from JPUD to supply power for its OCC facility, and BPA has preliminarily included the OCC load in JPUD's contract high water mark ("CHWM"). PTPC also needs to secure a long term and affordable source of power for its mill load. We ask that our mill load also be included in JPUD's CHWM, so that we could be assured a long-term affordable power supply. JPUD could then use BPA's tier 1 power to serve the mill. JPUD has expressed its desire to provide this service.

PTPC understands that no more than 9.9 MW of the mill load could be shifted per year and that the total Tier 1 entitlement for new public utilities also is limited to a maximum of 50 MW per rate period. We seek no changes to these limitations.

I understand that BPA has the statutory authority to allow PTPC to shift its mill load per year to JPUD in up to 9.9 MW annual amounts without becoming a new large single load ("NLSL"). Under this statutory authority, Port Townsend could move its load entirely to the PUD by the second year of the PUD's operation. However, I also understand that in the past, BPA has been unwilling to allow PTPC to make such shifts because such allowance would constitute a change in BPA's NLSL policy.

NLSLs, as defined in the Northwest Power Planning and Conservation Act, are not eligible for service at favorable BPA rates. The BPA NLSL policy has been more restrictive on Port Townsend than the requirements of applicable law, based on policy considerations that are no longer applicable.

The Northwest Power Planning and Conservation Act makes clear that a load is a NLSL only if it results in an increase in power requirements <u>of a utility customer</u> of ten average megawatts or more in any consecutive twelve-month period:

> "'New Large Single Load' means any load associated with a new facility, an existing facility, or an expansion of an existing facility:
>
> (1) which is not contracted for, or committed to, as determined by Bonneville, by a public body, cooperative, investor-owned utility, or Federal agency Customer prior to September 1, 1979, and
>
> (2) which will result in an increase in power requirements of such Customer of ten average megawatts or more in any consecutive twelve month period."

Even though the applicable statutory prohibition only applies if the <u>utility customer</u> takes on new facility loads greater than 10 average megawatts in a 12-month period, BPA policy historically has barred its DSI customers from shifting their loads to BPA's Customers in annual amounts of less than 10 average megawatts. This prohibition served to ensure that the DSIs like PTPC continued to purchase power from BPA at its industrial power ("IP") rates. However, BPA now believes that court decisions restrict its ability to offer power at the IP rate. Thus, this reason for preventing Port Townsend's relatively modest load from migrating to JPUD no longer exists.

In a January 15, 2003 policy discussion paper, BPA put out for discussion various policy options available to BPA for treatment of DSI 1981 Contract Demand that shifted to a BPA utility customer. The options were (a) continue to treat all such shifted load as an NLSL load, even if the shifted load were less than 10 average megawatts, (b) allow a shift of less than 10 average megawatts, without triggering NLSL status, if BPA reduced its IP contract demand to such DSI below the 1981 Contract Demand, or (c) allow annual shifts of 9.9 average megawatts without a triggering of NLSL status.

In its Summary of January 2005 Regional Dialogue Policy Decisions, BPA stated that it had decided to retain option (a), which would not allow additional phase-in of DSI 1981 Contract Demands. That decision relied on BPA's belief that it had other tools available to address continuing service to DSIs, such as provision of service at a negotiated Section 7(f) rate. The paper stated "[t]his policy does not preclude BPA from selling surplus firm power consistent with Section 5(f) of the Northwest Power Act to utility customers at a Section 7(f) rate to serve former DSI load." In subsequent decisions, however, the Ninth Circuit denied BPA the power marketing flexibility it thought it had and that justified retention of its restrictive policy.

Port Townsend requests BPA now employ option (c) and allow JPUD include in its CHWM both the OCC load and the load for balance of the mill. The creation of JPUD's CHWM represents a one-time opportunity for BPA to save hundreds of good jobs that families in Jefferson County rely on, and I urge BPA to act with these families in mind.