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

Attachments to

POWER SALE TO ALCOA INC.
COMMENCING DECEMBER 22, 2009

ADMINISTRATOR'S RECORD OF DECISION

December 21, 2009

BONNEVILLE
POWER ADMINISTRATION

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Attachment A

Letter increasing Contract Demand to 468 MW

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

In reply refer to: P

SEP 11 1987

Contract Demand
& operating demand
462 MW

Mr. Noel Shelton, Northwest Power Manager
Intalco Aluminum Corporation
Suite 3508
1300 SW. 5th Avenue
Portland, OR 97201

Dear Noel:

The Bonneville Power Administration (BPA) has reviewed your June 18, 1987, request for a Technological Allowance. Section 5(d)(1) of the Power Sales Contract cites "improvements in the operation of equipment" as one of four justifications for granting a Technological Allowance. George Reich, Puget Sound Area Power Manager, has inspected Intalco's plant, and has recommended that your proposal satisfies this criterion and be approved.

BPA understands that you will use the Technological Allowance to provide increased amperage to your pots. This increase is required by:

1. cathode design changes,
2. improvements in your ability to predict anode effects (which reduce the heat in the pot), and
3. improved operating procedures.

These technological improvements will have the side effect of reducing the heat in your pots, thereby reducing the amount of aluminum you can produce with your existing equipment. BPA agrees that the operation of Intalco's potlines would be impaired by thermal imbalance without the granting of this Technological Allowance. Also, any increase must be consistent with the demand meter multiplier which only measures power in 0.8 MW increments. The above Technological Allowance amounts to 11.18 MW. The closest increment, therefore, is 11.2 MW. This upward adjustment is consistent with BPA's September 1, 1983, response to Intalco's earlier request for a Technological Allowance of 7.4 MW. At that time, due to the need to measure power in 0.8 MW increments, BPA granted an increase of only 7.2 MW. Thus, the upward adjustment of 0.02 MW in 1987 has the effect of partially offsetting the downward adjustment of 0.2 MW in 1983.

Also, in recent discussions you have requested that Intalco's Operating Demand be likewise increased. Consequently, effective September 1, 1987, both your Contract Demand and Operating Demand will be increased from 456.8 MW to 468.0 MW. A revised Exhibit C to your Power Sales Contract is enclosed.

Sincerely,

Walter F. Pollock

for Edward W. Sienkiewicz
Assistant Administrator for
Power Marketing

Enclosure

Exhibit C, Page 1 of 1
Contract No. DE-MS79-81BP90350
Intalco Aluminum Corporation
Effective at 2400 hours on
September 1, 1987

Contract Demand: 468.0 MW

Operating Demand: 468.0 MW

Auxiliary Demand: None

(PKL-2068b)

Attachment B

Tables 1-7, Loads & Resources data input into RevSim

TABLE 1

Loads and Resources - Federal System

PNW Loads and Resource Study

2009 - 2010 Fiscal Years 7/21/2009

1937 Water Year

[59] 2010 Final Rate Case - 30 Minute Wind (Final)

Energy (aMW)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
Non-Utility Obligations													
Fed. Agencies 2002 PSC	106	126	139	145	137	124	114	108	105	117	119	109	121
USBR 2002 PSC	94	14	31	70	79	50	224	289	286	310	256	219	161
DSI 2002 PSC	402	402	402	402	402	402	402	402	402	402	402	402	402
Fed. Agencies 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
USBR 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
DSI 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Non-Utility Obligations	603	542	572	617	618	577	740	799	793	829	777	729	683
Transfers Out													
NGP 2002 PSC	2,776	3,207	3,586	3,647	3,476	3,011	2,922	2,907	3,033	3,229	3,123	2,849	3,146
GPU 2002 PSC	2,015	2,505	2,756	2,719	2,695	2,481	2,135	1,935	1,831	1,896	1,970	2,093	2,250
NGP 2002 Slice PSC	576	681	655	659	588	555	449	744	635	622	621	563	613
GPU 2002 Slice PSC	959	1,134	1,091	1,098	979	924	747	1,238	1,057	1,036	1,033	938	1,021
IOU 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
NGP 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
GPU 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
NGP 2012 Slice PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
GPU 2012 Slice PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
IOU 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
Exports	694	693	701	693	691	694	726	756	759	749	696	686	712
Regional Transfers (Out)	328	639	670	693	657	523	473	451	266	266	444	253	471
Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transfers Out	7,348	8,860	9,458	9,509	9,085	8,189	7,453	8,031	7,582	7,797	7,887	7,383	8,212
Total Firm Obligations	**7,950**	**9,403**	**10,030**	**10,126**	**9,703**	**8,765**	**8,192**	**8,830**	**8,374**	**8,627**	**8,663**	**8,112**	**8,896**
Hydro Resources													
Regulated Hydro	6,079	7,302	7,093	7,197	6,345	5,812	4,561	7,896	6,522	6,684	6,627	5,928	6,510
Independent Hydro	336	297	210	188	186	275	420	730	783	496	446	421	400
Operational Peaking Adj.	0	0	0	0	0	0	0	0	0	0	0	0	0
Non-Fed CER (Canada)	137	137	137	137	137	137	141	141	141	141	141	141	139
											0		
Total Hydro Resources	**6,552**	**7,736**	**7,440**	**7,522**	**6,669**	**6,224**	**5,122**	**8,767**	**7,446**	**7,322**	**7,214**	**6,490**	**7,049**
Other Resources													
Small Thermal & Misc.	0	0	0	0	0	0	0	0	0	0	0	0	0
Combustion Turbines	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	57	61	59	62	60	81	72	74	80	66	61	52	65
Cogeneration	22	25	26	27	27	26	25	22	12	20	20	21	23
Imports	217	297	367	367	344	332	300	136	134	165	163	155	248
Regional Transfers (In)	244	302	232	249	241	218	216	220	234	214	230	248	237
Large Thermal	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030
Non-Utility Generation	13	26	30	29	26	25	45	41	27	19	26	9	26
Augmentation Purchases	476	476	476	476	476	476	476	476	476	476	476	476	476
Augmentation Resources	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Other Resources	2,059	2,216	2,220	2,241	2,203	2,187	2,164	1,999	1,993	1,990	2,005	1,990	2,105
Total Resources	**8,611**	**9,952**	**9,659**	**9,763**	**8,872**	**8,411**	**7,286**	**10,766**	**9,439**	**9,311**	**9,219**	**8,480**	**9,154**
Reserves & Maintenance													
Contingency Reserves (Non-Spinning)	0	0	0	0	0	0	0	0	0	0	0	0	0
Contingency Reserves (Spinning)	0	0	0	0	0	0	0	0	0	0	0	0	0
Generation Imbalance Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0
Load Following Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Hydro Maintenance	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Transmission Losses	(243)	(281)	(272)	(275)	(250)	(237)	(205)	(304)	(266)	(263)	(260)	(239)	(258)
Total Reserves, Maintenance & Losses	(243)	(281)	(272)	(275)	(250)	(237)	(205)	(304)	(266)	(263)	(260)	(239)	(258)
Total Net Resources	**8,368**	**9,672**	**9,387**	**9,488**	**8,621**	**8,174**	**7,081**	**10,462**	**9,173**	**9,049**	**8,959**	**8,241**	**8,896**
Total Firm Surplus/Deficit	**418**	**269**	**(643)**	**(638)**	**(1,082)**	**(592)**	**(1,112)**	**1,632**	**799**	**422**	**296**	**129**	**(0)**

TABLE 2

Loads and Resources - Federal System

PNW Loads and Resource Study

2010 - 2011 Fiscal Years **7/21/2009**

1937 Water Year

[59] 2010 Final Rate Case - 30 Minute Wind (Final)

Energy (aMW)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
Non-Utility Obligations													
Fed. Agencies 2002 PSC	110	130	143	148	140	126	115	110	107	119	121	110	123
USBR 2002 PSC	94	14	31	70	79	50	224	289	286	310	256	219	161
DSI 2002 PSC	402	402	402	402	402	402	402	402	402	402	402	402	402
Fed. Agencies 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
USBR 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
DSI 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Non-Utility Obligations	606	547	577	620	621	579	742	801	794	831	779	731	686
Transfers Out													
NGP 2002 PSC	2,834	3,265	3,636	3,703	3,524	3,064	2,974	2,956	3,082	3,293	3,171	2,895	3,199
GPU 2002 PSC	2,014	2,507	2,756	2,719	2,696	2,481	2,136	1,935	1,831	1,898	1,966	2,093	2,250
NGP 2002 Slice PSC	580	686	660	663	592	559	390	663	554	615	622	565	596
GPU 2002 Slice PSC	967	1,142	1,098	1,105	986	931	649	1,103	922	1,024	1,036	940	993
IOU 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
NGP 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
GPU 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
NGP 2012 Slice PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
GPU 2012 Slice PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
IOU 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
Exports	645	648	653	645	644	648	681	709	718	709	687	676	672
Regional Transfers (Out)	328	637	667	691	657	523	473	451	266	266	275	59	440
Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transfers Out	7,368	8,884	9,470	9,526	9,100	8,206	7,303	7,816	7,373	7,806	7,757	7,229	8,150
Total Firm Obligations	**7,974**	**9,430**	**10,047**	**10,146**	**9,721**	**8,785**	**8,044**	**8,617**	**8,168**	**8,637**	**8,535**	**7,960**	**8,836**
Hydro Resources													
Regulated Hydro	6,085	7,311	7,100	7,205	6,352	5,817	4,565	7,903	6,528	6,692	6,635	5,934	6,517
Independent Hydro	336	297	210	188	186	275	420	730	783	496	446	421	400
Operational Peaking Adj.	0	0	0	0	0	0	0	0	0	0	0	0	0
Non-Fed CER (Canada)	141	141	141	141	141	141	139	139	139	139	139	139	140
											0		
Total Hydro Resources	**6,562**	**7,748**	**7,451**	**7,534**	**6,679**	**6,234**	**5,124**	**8,772**	**7,450**	**7,327**	**7,220**	**6,494**	**7,057**
Other Resources													
Small Thermal & Misc.	0	0	0	0	0	0	0	0	0	0	0	0	0
Combustion Turbines	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	57	61	59	62	60	81	72	74	80	66	61	52	65
Cogeneration	22	25	26	27	27	26	25	22	12	20	20	21	23
Imports	206	285	356	356	334	321	292	130	134	165	163	154	241
Regional Transfers (In)	235	293	223	240	231	216	214	217	230	211	227	51	216
Large Thermal	1,030	1,030	1,030	1,030	1,030	1,030	275	0	0	897	1,030	1,030	785
Non-Utility Generation	13	26	30	29	26	25	45	41	27	19	26	9	26
Augmentation Purchases	680	680	680	680	680	680	680	680	680	680	680	680	680
Augmentation Resources	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Other Resources	2,243	2,400	2,403	2,426	2,388	2,379	1,604	1,164	1,163	2,059	2,207	1,998	2,036
Total Resources	**8,805**	**10,148**	**9,855**	**9,960**	**9,067**	**8,613**	**6,728**	**9,936**	**8,614**	**9,386**	**9,427**	**8,492**	**9,093**
Reserves & Maintenance													
Contingency Reserves (Non-Spinning)	0	0	0	0	0	0	0	0	0	0	0	0	0
Contingency Reserves (Spinning)	0	0	0	0	0	0	0	0	0	0	0	0	0
Generation Imbalance Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0
Load Following Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Hydro Maintenance	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Transmission Losses	(248)	(286)	(278)	(281)	(256)	(243)	(190)	(280)	(243)	(265)	(266)	(239)	(256)
Total Reserves, Maintenance & Losses	(248)	(286)	(278)	(281)	(256)	(243)	(190)	(280)	(243)	(265)	(266)	(239)	(256)
Total Net Resources	**8,557**	**9,862**	**9,577**	**9,679**	**8,811**	**8,370**	**6,539**	**9,655**	**8,371**	**9,121**	**9,161**	**8,252**	**8,836**
Total Firm Surplus/Deficit	**583**	**432**	**(470)**	**(467)**	**(909)**	**(415)**	**(1,506)**	**1,039**	**203**	**484**	**626**	**293**	**(0)**

TABLE 3

Loads and Resources - Federal System

PNW Loads and Resource Study

2011 - 2012 Fiscal Years **7/21/2009**

1937 Water Year

[59] 2010 Final Rate Case - 30 Minute Wind (Final)

Energy (aMW)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
Non-Utility Obligations													
Fed. Agencies 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
USBR 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
DSI 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
Fed. Agencies 2012 PSC	111	133	146	150	143	129	117	111	108	121	123	112	125
USBR 2012 PSC	94	14	31	70	85	50	224	289	286	310	256	219	161
DSI 2012 PSC	402	402	402	402	402	402	402	402	402	402	402	402	402
Total Firm Non-Utility Obligations	608	549	580	622	629	581	743	803	796	833	781	733	688
Transfers Out													
NGP 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
GPU 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
NGP 2002 Slice PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
GPU 2002 Slice PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
IOU 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
NGP 2012 PSC	3,149	3,616	4,013	4,054	3,866	3,391	3,268	3,264	3,403	3,641	3,517	3,244	3,535
GPU 2012 PSC	1,601	1,913	2,122	2,123	1,934	1,819	1,649	1,498	1,444	1,447	1,456	1,447	1,704
NGP 2012 Slice PSC	367	424	406	409	363	347	279	468	397	391	391	356	384
GPU 2012 Slice PSC	1,497	1,730	1,658	1,667	1,480	1,417	1,138	1,909	1,621	1,595	1,595	1,454	1,565
IOU 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
Exports	600	599	602	595	593	598	634	666	673	661	637	630	624
Regional Transfers (Out)	145	408	480	479	458	345	301	54	92	108	72	59	249
Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transfers Out	7,358	8,690	9,281	9,327	8,693	7,918	7,269	7,858	7,630	7,843	7,668	7,191	8,061
Total Firm Obligations	**7,966**	**9,239**	**9,861**	**9,949**	**9,322**	**8,499**	**8,012**	**8,661**	**8,426**	**8,676**	**8,449**	**7,923**	**8,749**
Hydro Resources													
Regulated Hydro	6,116	7,349	7,137	7,243	6,385	5,847	4,587	7,942	6,559	6,724	6,669	5,963	6,549
Independent Hydro	329	287	198	179	176	262	404	708	761	476	431	411	385
Operational Peaking Adj.	0	0	0	0	0	0	0	0	0	0	0	0	0
Non-Fed CER (Canada)	139	139	139	139	139	139	138	138	138	138	138	138	138
											0		
Total Hydro Resources	**6,585**	**7,775**	**7,474**	**7,561**	**6,700**	**6,248**	**5,128**	**8,787**	**7,457**	**7,337**	**7,238**	**6,512**	**7,073**
Other Resources													
Small Thermal & Misc.	0	0	0	0	0	0	0	0	0	0	0	0	0
Combustion Turbines	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	57	61	59	62	60	81	72	73	80	66	61	52	65
Cogeneration	22	25	26	27	27	26	25	22	12	20	20	21	23
Imports	206	284	355	356	334	321	294	130	134	165	163	153	241
Regional Transfers (In)	45	57	27	21	24	32	36	42	47	44	33	44	38
Large Thermal	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030
Non-Utility Generation	13	26	30	18	9	3	3	3	3	3	3	3	10
Augmentation Purchases	524	524	524	524	524	524	524	524	524	524	524	524	524
Augmentation Resources	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Other Resources	1,897	2,006	2,050	2,039	2,008	2,016	1,983	1,824	1,830	1,852	1,834	1,827	1,930
Total Resources	**8,481**	**9,781**	**9,524**	**9,600**	**8,707**	**8,264**	**7,112**	**10,611**	**9,288**	**9,190**	**9,072**	**8,339**	**9,003**
Reserves & Maintenance													
Contingency Reserves (Non-Spinning)	0	0	0	0	0	0	0	0	0	0	0	0	0
Contingency Reserves (Spinning)	0	0	0	0	0	0	0	0	0	0	0	0	0
Generation Imbalance Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0
Load Following Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Hydro Maintenance	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Transmission Losses	(239)	(276)	(269)	(271)	(246)	(233)	(201)	(299)	(262)	(259)	(256)	(235)	(254)
Total Reserves, Maintenance & Losses	(239)	(276)	(269)	(271)	(246)	(233)	(201)	(299)	(262)	(259)	(256)	(235)	(254)
Total Net Resources	**8,242**	**9,505**	**9,255**	**9,329**	**8,462**	**8,031**	**6,911**	**10,312**	**9,026**	**8,930**	**8,817**	**8,104**	**8,749**
Total Firm Surplus/Deficit	**276**	**266**	**(605)**	**(620)**	**(860)**	**(467)**	**(1,101)**	**1,651**	**600**	**254**	**368**	**180**	**(0)**

TABLE 4
Loads and Resources - Federal System
PNW Loads and Resource Study
2012 - 2013 Fiscal Years
1937 Water Year
[59] 2010 Final Rate Case - 30 Minute Wind (Final)

7/21/2009

Energy (aMW)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
Non-Utility Obligations													
Fed. Agencies 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
USBR 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
DSI 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
Fed. Agencies 2012 PSC	113	135	149	152	144	130	119	113	109	123	124	113	127
USBR 2012 PSC	94	14	31	70	79	50	224	289	286	310	256	219	161
DSI 2012 PSC	402	402	402	402	402	402	402	402	402	402	402	402	402
Total Firm Non-Utility Obligations	609	551	582	624	625	582	745	804	797	835	782	734	689
Transfers Out													
NGP 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
GPU 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
NGP 2002 Slice PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
GPU 2002 Slice PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
IOU 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
NGP 2012 PSC	3,213	3,684	4,084	4,142	3,947	3,462	3,336	3,352	3,472	3,715	3,590	3,312	3,608
GPU 2012 PSC	1,621	1,932	2,140	2,142	2,015	1,838	1,668	1,518	1,464	1,468	1,477	1,468	1,728
NGP 2012 Slice PSC	367	424	406	409	364	348	280	433	345	387	392	357	376
GPU 2012 Slice PSC	1,499	1,730	1,657	1,668	1,484	1,421	1,142	1,766	1,408	1,578	1,599	1,457	1,536
IOU 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
Exports	589	587	590	583	581	586	622	654	660	650	627	621	613
Regional Transfers (Out)	145	408	480	479	458	345	301	54	92	108	72	59	249
Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transfers Out	7,434	8,765	9,357	9,423	8,849	8,001	7,348	7,778	7,441	7,905	7,756	7,274	8,109
Total Firm Obligations	**8,044**	**9,316**	**9,939**	**10,047**	**9,474**	**8,583**	**8,092**	**8,581**	**8,239**	**8,739**	**8,538**	**8,008**	**8,799**
Hydro Resources													
Regulated Hydro	6,125	7,361	7,147	7,255	6,395	5,855	4,593	7,952	6,567	6,734	6,681	5,972	6,559
Independent Hydro	329	287	198	179	176	262	404	708	761	476	431	411	386
Operational Peaking Adj.	0	0	0	0	0	0	0	0	0	0	0	0	0
Non-Fed CER (Canada)	138	138	138	138	138	138	136	136	136	136	136	136	137
											0		
Total Hydro Resources	**6,592**	**7,785**	**7,483**	**7,571**	**6,708**	**6,255**	**5,133**	**8,796**	**7,465**	**7,346**	**7,249**	**6,519**	**7,082**
Other Resources													
Small Thermal & Misc.	0	0	0	0	0	0	0	0	0	0	0	0	0
Combustion Turbines	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	57	61	59	62	60	81	72	73	81	66	61	52	65
Cogeneration	22	25	26	27	27	26	25	22	12	20	20	21	23
Imports	207	284	356	355	334	323	293	130	134	166	163	154	241
Regional Transfers (In)	45	57	26	21	24	32	36	42	48	44	33	44	38
Large Thermal	1,030	1,030	1,030	1,030	1,030	1,030	1,030	332	0	930	1,030	1,030	878
Non-Utility Generation	3	3	3	3	3	3	3	3	3	3	3	3	3
Augmentation Purchases	725	725	725	725	725	725	725	725	725	725	725	725	725
Augmentation Resources	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Other Resources	2,088	2,183	2,225	2,223	2,203	2,219	2,183	1,327	1,002	1,953	2,035	2,029	1,972
Total Resources	**8,681**	**9,969**	**9,708**	**9,794**	**8,911**	**8,473**	**7,316**	**10,124**	**8,466**	**9,300**	**9,283**	**8,547**	**9,054**
Reserves & Maintenance													
Contingency Reserves (Non-Spinning)	0	0	0	0	0	0	0	0	0	0	0	0	0
Contingency Reserves (Spinning)	0	0	0	0	0	0	0	0	0	0	0	0	0
Generation Imbalance Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0
Load Following Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Hydro Maintenance	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Transmission Losses	(245)	(281)	(274)	(276)	(251)	(239)	(206)	(285)	(239)	(262)	(262)	(241)	(255)
Total Reserves, Maintenance & Losses	(245)	(281)	(274)	(276)	(251)	(239)	(206)	(285)	(239)	(262)	(262)	(241)	(255)
Total Net Resources	**8,436**	**9,687**	**9,434**	**9,518**	**8,659**	**8,234**	**7,110**	**9,838**	**8,228**	**9,037**	**9,022**	**8,306**	**8,799**
Total Firm Surplus/Deficit	**392**	**371**	**(505)**	**(529)**	**(815)**	**(348)**	**(982)**	**1,257**	**(11)**	**298**	**484**	**298**	**(0)**

TABLE 5

Loads and Resources - Federal System

PNW Loads and Resource Study

2013 - 2014 Fiscal Years **7/21/2009**

1937 Water Year

[59] 2010 Final Rate Case - 30 Minute Wind (Final)

Energy (aMW)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
Non-Utility Obligations													
Fed. Agencies 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
USBR 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
DSI 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
Fed. Agencies 2012 PSC	114	136	150	171	161	144	131	125	122	137	137	125	138
USBR 2012 PSC	94	14	31	70	79	50	224	289	286	310	256	219	161
DSI 2012 PSC	402	402	402	402	402	402	402	402	402	402	402	402	402
Total Firm Non-Utility Obligations	610	553	584	643	642	597	757	816	809	849	795	746	700
Transfers Out													
NGP 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
GPU 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
NGP 2002 Slice PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
GPU 2002 Slice PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
IOU 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
NGP 2012 PSC	3,280	3,754	4,159	4,216	4,019	3,528	3,401	3,395	3,539	3,785	3,659	3,377	3,675
GPU 2012 PSC	1,646	1,957	2,166	2,167	2,040	1,863	1,693	1,543	1,489	1,492	1,502	1,493	1,753
NGP 2012 Slice PSC	368	425	411	409	364	349	277	470	401	395	393	357	385
GPU 2012 Slice PSC	1,502	1,734	1,677	1,671	1,486	1,423	1,130	1,918	1,636	1,611	1,604	1,457	1,572
IOU 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
Exports	579	577	580	573	571	576	612	644	651	640	614	609	602
Regional Transfers (Out)	145	408	480	479	458	345	301	54	58	74	72	59	243
Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transfers Out	7,521	8,855	9,472	9,515	8,939	8,083	7,414	8,023	7,774	7,997	7,843	7,352	8,231
Total Firm Obligations	**8,131**	**9,408**	**10,056**	**10,158**	**9,581**	**8,680**	**8,172**	**8,839**	**8,583**	**8,846**	**8,638**	**8,098**	**8,931**
Hydro Resources													
Regulated Hydro	6,134	7,372	7,232	7,257	6,396	5,855	4,531	7,963	6,576	6,745	6,693	5,980	6,568
Independent Hydro	329	287	198	179	176	262	404	708	761	476	431	411	386
Operational Peaking Adj.	0	0	0	0	0	0	0	0	0	0	0	0	0
Non-Fed CER (Canada)	136	136	136	136	136	136	135	135	135	135	135	135	135
											0		
Total Hydro Resources	**6,600**	**7,795**	**7,566**	**7,572**	**6,708**	**6,253**	**5,069**	**8,806**	**7,472**	**7,355**	**7,259**	**6,526**	**7,089**
Other Resources													
Small Thermal & Misc.	0	0	0	0	0	0	0	0	0	0	0	0	0
Combustion Turbines	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	57	61	59	62	60	81	72	73	81	66	61	52	65
Cogeneration	22	25	26	27	27	26	25	22	12	20	20	21	23
Imports	207	284	357	355	334	322	293	130	134	166	162	154	241
Regional Transfers (In)	45	57	26	21	24	32	36	42	48	44	33	21	36
Large Thermal	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030
Non-Utility Generation	3	3	3	3	3	3	3	3	3	3	3	3	3
Augmentation Purchases	704	704	704	704	704	704	704	704	704	704	704	704	704
Augmentation Resources	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Other Resources	2,067	2,162	2,204	2,202	2,182	2,198	2,162	2,004	2,011	2,032	2,013	1,985	2,102
Total Resources	**8,667**	**9,958**	**9,770**	**9,774**	**8,889**	**8,451**	**7,231**	**10,810**	**9,482**	**9,388**	**9,272**	**8,511**	**9,190**
Reserves & Maintenance													
Contingency Reserves (Non-Spinning)	0	0	0	0	0	0	0	0	0	0	0	0	0
Contingency Reserves (Spinning)	0	0	0	0	0	0	0	0	0	0	0	0	0
Generation Imbalance Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0
Load Following Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Hydro Maintenance	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Transmission Losses	(244)	(281)	(276)	(276)	(251)	(238)	(204)	(305)	(267)	(265)	(261)	(240)	(259)
Total Reserves, Maintenance & Losses	(244)	(281)	(276)	(276)	(251)	(238)	(204)	(305)	(267)	(265)	(261)	(240)	(259)
Total Net Resources	**8,423**	**9,677**	**9,495**	**9,498**	**8,639**	**8,212**	**7,027**	**10,505**	**9,215**	**9,123**	**9,011**	**8,271**	**8,931**
Total Firm Surplus/Deficit	**291**	**269**	**(561)**	**(660)**	**(942)**	**(468)**	**(1,144)**	**1,666**	**632**	**277**	**372**	**173**	**(0)**

TABLE 6
Loads and Resources - Federal System
PNW Loads and Resource Study
2014 - 2015 Fiscal Years **7/21/2009**
1937 Water Year
[59] 2010 Final Rate Case - 30 Minute Wind (Final)

Energy (aMW)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
Non-Utility Obligations													
Fed. Agencies 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
USBR 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
DSI 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
Fed. Agencies 2012 PSC	127	153	169	176	165	148	135	128	125	140	141	128	144
USBR 2012 PSC	94	14	31	70	79	50	224	289	286	310	256	219	161
DSI 2012 PSC	402	402	402	402	402	402	402	402	402	402	402	402	402
Total Firm Non-Utility Obligations	623	569	602	648	646	600	761	819	813	852	799	749	707
Transfers Out													
NGP 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
GPU 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
NGP 2002 Slice PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
GPU 2002 Slice PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
IOU 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
NGP 2012 PSC	3,343	3,821	4,229	4,285	4,074	3,571	3,463	3,458	3,605	3,853	3,725	3,441	3,738
GPU 2012 PSC	1,669	1,981	2,189	2,191	2,064	1,886	1,716	1,566	1,512	1,515	1,525	1,515	1,776
NGP 2012 Slice PSC	368	425	425	408	363	348	267	443	348	382	394	357	378
GPU 2012 Slice PSC	1,500	1,732	1,735	1,666	1,482	1,419	1,091	1,808	1,422	1,557	1,606	1,458	1,541
IOU 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
Exports	567	564	568	561	559	564	600	630	637	623	598	593	589
Regional Transfers (Out)	145	408	480	479	458	345	301	54	58	74	72	59	243
Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transfers Out	7,591	8,931	9,626	9,590	9,000	8,133	7,438	7,959	7,581	8,004	7,918	7,424	8,265
Total Firm Obligations	**8,214**	**9,500**	**10,228**	**10,238**	**9,646**	**8,733**	**8,198**	**8,778**	**8,393**	**8,856**	**8,717**	**8,173**	**8,972**
Hydro Resources													
Regulated Hydro	6,134	7,372	7,498	7,222	6,364	5,824	4,334	7,963	6,576	6,745	6,693	5,980	6,566
Independent Hydro	329	287	198	179	176	262	404	708	761	476	431	411	386
Operational Peaking Adj.	0	0	0	0	0	0	0	0	0	0	0	0	0
Non-Fed CER (Canada)	135	135	135	135	135	135	133	133	133	133	133	133	134
											0		
Total Hydro Resources	**6,598**	**7,794**	**7,831**	**7,536**	**6,675**	**6,221**	**4,871**	**8,804**	**7,470**	**7,354**	**7,257**	**6,524**	**7,086**
Other Resources													
Small Thermal & Misc.	0	0	0	0	0	0	0	0	0	0	0	0	0
Combustion Turbines	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	57	61	59	62	60	81	72	74	80	66	61	52	65
Cogeneration	22	25	26	27	27	26	25	22	12	20	20	21	23
Imports	207	285	355	355	334	323	293	130	134	161	158	146	239
Regional Transfers (In)	22	34	27	21	24	32	36	43	47	44	33	21	32
Large Thermal	1,030	1,030	1,030	1,030	1,030	1,030	1,030	498	0	764	1,030	1,030	878
Non-Utility Generation	3	3	3	3	3	3	3	3	3	3	3	3	3
Augmentation Purchases	906	906	906	906	906	906	906	906	906	906	906	906	906
Augmentation Resources	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Other Resources	2,247	2,343	2,406	2,404	2,384	2,400	2,365	1,675	1,183	1,964	2,211	2,179	2,146
Total Resources	**8,845**	**10,137**	**10,236**	**9,940**	**9,059**	**8,621**	**7,236**	**10,479**	**8,653**	**9,318**	**9,469**	**8,704**	**9,232**
Reserves & Maintenance													
Contingency Reserves (Non-Spinning)	0	0	0	0	0	0	0	0	0	0	0	0	0
Contingency Reserves (Spinning)	0	0	0	0	0	0	0	0	0	0	0	0	0
Generation Imbalance Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0
Load Following Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Hydro Maintenance	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Transmission Losses	(249)	(286)	(289)	(280)	(255)	(243)	(204)	(296)	(244)	(263)	(267)	(245)	(260)
Total Reserves, Maintenance & Losses	(249)	(286)	(289)	(280)	(255)	(243)	(204)	(296)	(244)	(263)	(267)	(245)	(260)
Total Net Resources	**8,596**	**9,851**	**9,948**	**9,660**	**8,804**	**8,378**	**7,032**	**10,184**	**8,409**	**9,055**	**9,202**	**8,458**	**8,972**
Total Firm Surplus/Deficit	**382**	**351**	**(281)**	**(578)**	**(843)**	**(355)**	**(1,167)**	**1,406**	**16**	**200**	**485**	**286**	**(0)**

TABLE 7

Loads and Resources - Federal System

PNW Loads and Resource Study

2015 - 2016 Fiscal Years **7/21/2009**

1937 Water Year

[59] 2010 Final Rate Case - 30 Minute Wind (Final)

Energy (aMW)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
Non-Utility Obligations													
Fed. Agencies 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
USBR 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
DSI 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
Fed. Agencies 2012 PSC	130	157	174	178	168	150	136	129	126	142	142	130	147
USBR 2012 PSC	94	14	31	70	85	50	224	289	286	310	256	219	161
DSI 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Non-Utility Obligations	224	171	205	248	252	200	361	418	412	452	398	348	308
Transfers Out													
NGP 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
GPU 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
NGP 2002 Slice PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
GPU 2002 Slice PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
IOU 2002 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
NGP 2012 PSC	3,408	3,891	4,302	4,359	4,150	3,655	3,529	3,524	3,672	3,923	3,794	3,507	3,809
GPU 2012 PSC	1,722	2,036	2,246	2,248	2,057	1,941	1,770	1,619	1,564	1,568	1,578	1,568	1,826
NGP 2012 Slice PSC	371	427	414	413	367	352	279	474	406	398	396	360	389
GPU 2012 Slice PSC	1,512	1,744	1,691	1,685	1,499	1,437	1,140	1,934	1,655	1,623	1,616	1,468	1,585
IOU 2012 PSC	0	0	0	0	0	0	0	0	0	0	0	0	0
Exports	554	553	556	548	547	552	588	592	598	593	567	563	568
Regional Transfers (Out)	145	408	480	479	458	345	301	54	58	74	72	59	244
Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transfers Out	7,712	9,059	9,689	9,732	9,079	8,282	7,607	8,196	7,952	8,179	8,023	7,526	8,420
Total Firm Obligations	**7,937**	**9,230**	**9,894**	**9,980**	**9,331**	**8,483**	**7,968**	**8,614**	**8,364**	**8,631**	**8,421**	**7,874**	**8,728**
Hydro Resources													
Regulated Hydro	6,134	7,372	7,232	7,257	6,396	5,855	4,531	7,963	6,576	6,745	6,693	5,980	6,567
Independent Hydro	329	287	198	179	176	262	404	708	761	476	431	411	385
Operational Peaking Adj.	0	0	0	0	0	0	0	0	0	0	0	0	0
Non-Fed CER (Canada)	133	133	133	133	133	133	132	132	132	132	132	132	133
											0		
Total Hydro Resources	**6,597**	**7,792**	**7,563**	**7,569**	**6,705**	**6,250**	**5,066**	**8,803**	**7,469**	**7,352**	**7,256**	**6,523**	**7,085**
Other Resources													
Small Thermal & Misc.	0	0	0	0	0	0	0	0	0	0	0	0	0
Combustion Turbines	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	57	61	59	62	60	81	72	74	80	66	61	52	65
Cogeneration	22	25	26	27	27	26	0	0	0	0	0	0	13
Imports	202	281	351	352	330	319	292	130	134	150	148	135	235
Regional Transfers (In)	22	34	27	21	24	32	36	43	47	44	33	21	32
Large Thermal	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030
Non-Utility Generation	53	53	53	53	53	53	53	53	53	53	53	53	53
Augmentation Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
Augmentation Resources	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Other Resources	1,386	1,482	1,545	1,545	1,523	1,540	1,483	1,328	1,344	1,343	1,324	1,291	1,428
Total Resources	**7,983**	**9,275**	**9,108**	**9,114**	**8,228**	**7,790**	**6,549**	**10,131**	**8,813**	**8,695**	**8,580**	**7,814**	**8,513**
Reserves & Maintenance													
Contingency Reserves (Non-Spinning)	0	0	0	0	0	0	0	0	0	0	0	0	0
Contingency Reserves (Spinning)	0	0	0	0	0	0	0	0	0	0	0	0	0
Generation Imbalance Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0
Load Following Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Hydro Maintenance	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Transmission Losses	(225)	(262)	(257)	(257)	(232)	(220)	(185)	(286)	(249)	(245)	(242)	(220)	(240)
Total Reserves, Maintenance & Losses	(225)	(262)	(257)	(257)	(232)	(220)	(185)	(286)	(249)	(245)	(242)	(220)	(240)
Total Net Resources	**7,758**	**9,013**	**8,851**	**8,857**	**7,996**	**7,571**	**6,364**	**9,845**	**8,564**	**8,450**	**8,338**	**7,594**	**8,273**
Total Firm Surplus/Deficit	**(179)**	**(217)**	**(1,043)**	**(1,124)**	**(1,335)**	**(912)**	**(1,604)**	**1,231**	**200**	**(182)**	**(83)**	**(280)**	**(456)**

Attachment C

OMITTED, Tables 3-7 referred to are included in Attachment B

Attachment D

Alcoa comment dated August 3, 2009

August 3, 2009

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

Re: DSI Long-term Service

Dear Allen:

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

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

> "The rate or rates applicable to direct service industrial customers shall be established—
>
> for the period beginning July 1, 1985, at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region."

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

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

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

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

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

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

.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

<u>Conclusion</u>

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

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

Sincerely,

Mike Rousseau

Mike F. Rousseau
Plant Manger, Alcoa Intalco Works

cc: Governor Gregoire,
NW Congressional Delegation

Attachment E

Alcoa comment dated September 9, 2009

September 9, 2009

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

Re: 7-year Power Sale Agreement

Dear Allen:

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

Relative Rate Equity

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

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

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

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

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

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

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

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

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

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

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[4] Dick Conway and Associates, *The Economic Impact of the Intalco Works Aluminum Plant*, June 2008, page 4 (finding a multiplier effect of 2.9 additional jobs for each aluminum job in Washington).
[5] "Summary of BPA's Use of the Regional Economic Study to Contemplate the Service Concept."
http://www.bpa.gov/power/pl/regionaldialogue/implementation/documents/2009/2009-08-28_BPAsUse-of-RegionalEconomicStudy-for-Contemplation-of-ServiceConcept-Summary.pdf

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

DSI's historic benefits to BPA

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

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

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

a. Waiver of Rights to Surplus BPA Power

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

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

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

Slip. Op. at 11973.

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

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

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

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

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

b. Waiver of Lookback Claims

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

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

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

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

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

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

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

<u>Power reserves</u>

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

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

Proposed Power Sale Agreement at Exhibit F, Section 2.

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

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

Sincerely,

Mike Rousseau

Mike F. Rousseau
Plant Manger, Alcoa Intalco Works

cc: Governor Gregoire,
NW Congressional Delegation

Attachment F

Equivalent Benefits for 285 aMW

Benefits to BPA will equal or exceed costs for the Initial Period of the Block Contract from the sale of 285 aMW to Alcoa

BPA forecasts that the revenues it will accrue from the sale to Alcoa of 285 aMW or more, at the IP rate during the Initial Period, will exceed by approximately $151,000 the forecast revenues BPA could otherwise obtain from selling that power into the market for the Initial Period. See Tables 1-6 below. As a consequence, BPA believes service to Alcoa under the Block Contract is consistent *PNGC II*, that service to a DSI only can be provided if benefits equal or exceed costs.

BPA's projected monthly revenues are determined by multiplying the heavy load hour (HLH) and light load hour (LLH) energy entitlements and demand entitlement by their respective IP rates for each month. BPA has calculated revenues under the Block Contract based on a sale of 285 aMW of firm power each hour to Alcoa under the IP-10 rate schedule beginning December 22, 2009, the commencement of Firm Power deliveries pursuant to the Block Contract, and ending on May 31, 2011. The energy entitlements are the projected amounts of megawatt-hours to be sold by diurnal period each month. The demand entitlement is the megawatt amount consumed during the hour of BPA's system peak. Since the Block Contract sells the same number of megawatts in every hour of the month, the demand entitlement is the monthly megawatt amount specified in Table 1. BPA's projected monthly revenues are then accumulated and the result is illustrated in Tables 1 and 2:

TABLE 1 - Usage and Rates

Month	Alcoa Ferndale Usage			IP-10 Rates		
	Demand (kW)	HLH (MWh)	LLH (MWh)	Demand ($ / kW)	HLH ($ / MWh)	LLH ($ / MWh)
Dec-09	285,000	118,560	93,480	$2.30	$35.24	$31.13
Jan-10	285,000	114,000	98,040	$1.96	$38.46	$32.24
Feb-10	285,000	109,440	82,080	$1.99	$37.72	$31.73
Mar-10	285,000	123,120	88,635	$1.85	$35.94	$30.08
Apr-10	285,000	118,560	86,640	$1.74	$32.23	$26.95
May-10	285,000	114,000	98,040	$1.44	$31.69	$22.29
Jun-10	285,000	118,560	86,640	$1.32	$31.18	$23.29
Jul-10	285,000	118,560	93,480	$1.61	$33.33	$28.66
Aug-10	285,000	118,560	93,480	$1.89	$37.31	$31.40
Sep-10	285,000	114,000	91,200	$1.96	$36.49	$32.26
Oct-10	285,000	118,560	93,480	$2.05	$31.92	$27.01
Nov-10	285,000	114,000	91,485	$2.19	$33.33	$29.58
Dec-10	285,000	118,560	93,480	$2.30	$35.24	$31.13
Jan-11	285,000	114,000	98,040	$1.96	$38.46	$32.24
Feb-11	285,000	109,440	82,080	$1.99	$37.72	$31.73
Mar-11	285,000	123,120	88,635	$1.85	$35.94	$30.08
Apr-11	285,000	118,560	86,640	$1.74	$32.23	$26.95
May-11	285,000	114,000	98,040	$1.44	$31.69	$22.29
Jun-11	285,000	118,560	86,640	$1.32	$31.18	$23.29

TABLE 2 - BPA's Projected Revenue

Month	Revenues by Rate Determinant			Projected IP Revenue	
	Demand ($)	HLH ($)	LLH ($)	Month ($)	Cumulative ($)
Dec-09	$655,500	$4,178,054	$2,910,032	$7,743,587	$7,743,587
Jan-10	$558,600	$4,384,440	$3,160,810	$8,103,850	$15,847,436
Feb-10	$567,150	$4,128,077	$2,604,398	$7,299,625	$23,147,062
Mar-10	$527,250	$4,424,933	$2,666,141	$7,618,324	$30,765,385
Apr-10	$495,900	$3,821,189	$2,334,948	$6,652,037	$37,417,422
May-10	$410,400	$3,612,660	$2,185,312	$6,208,372	$43,625,794
Jun-10	$376,200	$3,696,701	$2,017,846	$6,090,746	$49,716,540
Jul-10	$458,850	$3,951,605	$2,679,137	$7,089,592	$56,806,132
Aug-10	$538,650	$4,423,474	$2,935,272	$7,897,396	$64,703,527
Sep-10	$558,600	$4,159,860	$2,942,112	$7,660,572	$72,364,099
Oct-10	$584,250	$3,784,435	$2,524,895	$6,893,580	$79,257,679
Nov-10	$624,150	$3,799,620	$2,706,126	$7,129,896	$86,387,576
Dec-10	$655,500	$4,178,054	$2,910,032	$7,743,587	$94,131,162
Jan-11	$558,600	$4,384,440	$3,160,810	$8,103,850	$102,235,012
Feb-11	$567,150	$4,128,077	$2,604,398	$7,299,625	$109,534,637
Mar-11	$527,250	$4,424,933	$2,666,141	$7,618,324	$117,152,961
Apr-11	$495,900	$3,821,189	$2,334,948	$6,652,037	$123,804,998
May-11	$410,400	$3,612,660	$2,185,312	$6,208,372	$130,013,369
Jun-11	$376,200	$3,696,701	$2,017,846	$6,090,746	$136,104,116

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

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

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

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

[3] BPA's natural gas forecast used in the WP-10 rate proceeding is outlined in section 3.3 of the Market Price Forecast Study. (See WP-10-FS-BPA-03, beginning on page 11.) BPA's more contemporary understanding of

In the absence of the Block Contract selling 285 aMW of firm power to Alcoa's Intalco Plant every hour BPA would have one less firm power requirement sale in its aggregated portfolio load shape to meet; as such BPA would have at least 285 aMW of surplus energy to sell in the market. As illustrated in Table 3, BPA has forecast the revenues it would otherwise obtain from the market using the same forecasting methodology applied in the WP-10 rate proceeding to incorporate our updated forecast of natural gas prices in the development of our electricity price forecast used in this analysis of the Block Contract for Alcoa.[4]

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

	Forecasted Market		Forecasted Revenues Obtained from the Market			
Month	HLH Price ($ / MWh)	LLH Price ($ / MWh)	HLH ($)	LLH ($)	Month ($) (HLH + LLH)	Cumulative ($)
Dec-09	$30.61	$27.41	$3,629,276	$2,562,520	$6,191,795	$6,191,795
Jan-10	$34.13	$29.51	$3,890,709	$2,893,014	$6,783,723	$12,975,518
Feb-10	$34.46	$29.77	$3,771,327	$2,443,489	$6,214,816	$19,190,334
Mar-10	$33.92	$29.16	$4,176,744	$2,584,569	$6,761,313	$25,951,647
Apr-10	$32.95	$28.05	$3,906,486	$2,430,524	$6,337,010	$32,288,657
May-10	$33.93	$24.45	$3,868,240	$2,397,135	$6,265,375	$38,554,032
Jun-10	$34.33	$26.33	$4,070,074	$2,281,208	$6,351,282	$44,905,314
Jul-10	$37.33	$32.18	$4,425,649	$3,007,802	$7,433,451	$52,338,765
Aug-10	$42.48	$35.63	$5,036,135	$3,330,266	$8,366,401	$60,705,166
Sep-10	$42.86	$38.00	$4,885,912	$3,465,283	$8,351,195	$69,056,361
Oct-10	$43.31	$36.85	$5,134,879	$3,444,617	$8,579,496	$77,635,857
Nov-10	$45.36	$40.59	$5,171,233	$3,713,177	$8,884,410	$86,520,267
Dec-10	$48.81	$43.42	$5,786,883	$4,059,167	$9,846,051	$96,366,318
Jan-11	$50.70	$42.13	$5,779,949	$4,130,138	$9,910,087	$106,276,405
Feb-11	$50.78	$42.80	$5,557,707	$3,512,895	$9,070,602	$115,347,007
Mar-11	$49.33	$40.83	$6,073,578	$3,618,868	$9,692,446	$125,039,452
Apr-11	$46.35	$38.79	$5,494,846	$3,360,763	$8,855,609	$133,895,061
May-11	$47.15	$32.65	$5,375,136	$3,201,218	$8,576,354	$142,471,415
Jun-11	$46.50	$33.58	$5,513,031	$2,909,798	$8,422,828	$150,894,243

Net Benefit (IP – Market)

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natural gas market fundamentals caused a lowering of its natural gas price forecast in 2010 and an increase in 2011. The primary reasons for BPA's recent reductions became apparent in the progression of time since the natural gas price forecast for the WP-10 rate proceeding was constructed; these are: a) continued strength of natural gas production despite steep reductions in rig counts, b) continued slow recovery of natural gas demand – particularly on the industrial side, c) record amount of natural gas in storage, d) reduced risk of hurricane impact on supply now that the 2009 hurricane season is nearly over. (See also Short-term Energy Outlooks from the EIA for September and October that have reduced their forecasted Henry Hub Spot Price average for 2010 to $4.78 and $5.02 per Mcf respectively [or $4.64 and $4.87 per MMbtu using EIA's conversion of 1 Mcf = 1.031 MMbtu], *Short-term Energy Outlook*, DOE EIA, September 9, 2009, page 1; *Short-Term Energy and Winter Fuels Outlook*, DOE EIA, October 6, 2009, p. 3.)

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

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

TABLE 4 - BPA's Net Benefit before Adjustment

Month	Net Revenue or (Cost) Month ($)	Net Revenue or (Cost) Cumulative ($)
Dec-09	$1,551,791	$1,551,791
Jan-10	$1,320,127	$2,871,918
Feb-10	$1,084,809	$3,956,728
Mar-10	$857,010	$4,813,738
Apr-10	$315,027	$5,128,765
May-10	($57,003)	$5,071,762
Jun-10	($260,536)	$4,811,226
Jul-10	($343,859)	$4,467,366
Aug-10	($469,005)	$3,998,361
Sep-10	($690,623)	$3,307,738
Oct-10	($1,685,916)	$1,621,822
Nov-10	($1,754,514)	($132,692)
Dec-10	($2,102,464)	($2,235,156)
Jan-11	($1,806,237)	($4,041,393)
Feb-11	($1,770,977)	($5,812,370)
Mar-11	($2,074,122)	($7,886,492)
Apr-11	($2,203,572)	($10,090,064)
May-11	($2,367,982)	($12,458,046)
Jun-11	($2,332,082)	($14,790,128)

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

BPA has identified a number of tangible benefits to BPA that would not be achieved by a market sale of power compared to a sale to Alcoa under the Block Contract at the IP rate. BPA conducted an economic analysis to determine the value of those benefits and included them in its analysis of the net value of the Block Contract to BPA. There were other, less tangible benefits accruing to BPA but assigning a financial value to those would have been more subjective, and based on the analysis below, doing so was unnecessary.

Value of Reserves

The Block Contract requires that Alcoa make contingency reserves available to BPA, reserves that would not be available from making a typical market sale. BPA takes into account the value to BPA of the reserves Alcoa is required to make available to BPA under the Block Contract.

Sales at the IP rate reflect the value of a right for BPA to obtain contingency reserves.[5] Specifically, the energy rate tables in the IP-10 rate schedule include an $0.80 per MWh credit for the value of these reserves. Therefore, BPA's net benefit above compares a surplus power sale to a sale of power at the IP rate with reserves. We have adjusted for this by adding back a value of reserves that provides an equal and opposite offset to the $0.80 per MWh credit for the value of reserves in the IP-10 rate schedule.[6] As illustrated by Table 5a, this is done for every megawatt hour not sold to Alcoa:

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

Month	Month ($)	Cumulative ($)
Dec-09	$169,632	$169,632
Jan-10	$169,632	$339,264
Feb-10	$153,216	$492,480
Mar-10	$169,404	$661,884
Apr-10	$164,160	$826,044
May-10	$169,632	$995,676
Jun-10	$164,160	$1,159,836
Jul-10	$169,632	$1,329,468
Aug-10	$169,632	$1,499,100
Sep-10	$164,160	$1,663,260
Oct-10	$169,632	$1,832,892
Nov-10	$164,388	$1,997,280
Dec-10	$169,632	$2,166,912
Jan-11	$169,632	$2,336,544
Feb-11	$153,216	$2,489,760
Mar-11	$169,404	$2,659,164
Apr-11	$164,160	$2,823,324
May-11	$169,632	$2,992,956
Jun-11	$164,160	$3,157,116

Avoided Transmission and Ancillary Services Expenses

When BPA makes a DSI sale, the DSI customers – including Alcoa – cover the cost of transmission and ancillary services through their own transmission contracts. Market prices, on the other hand, assume power is delivered by the seller to Mid-Columbia trading hub (Mid-C). Power Services (PS) is the organization within BPA that is responsible for the management and sale of Federal power. PS must pay the transmission and ancillary services costs to move surplus power to the Mid-C delivery point in order to realize the full market value for its surplus sales. PS maintains an inventory of transmission products and services to deliver the surplus power it intends to sell. However, this inventory is not sufficient to deliver all of the surplus power PS

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

[6] 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.

would sell under all load and resource conditions, especially under high stream flows. As a result, there is a subset of load and resource conditions under which PS would incur incremental costs for transmission and ancillary services to deliver incremental surplus energy sales, if PS did not sign contracts to serve the DSI loads -– including the Block Contract with Alcoa. The planned transmission and ancillary services expenses to address both the expected expenses and their uncertainty were addressed in the WP-10 rate proceeding.[7] Since PS overall marketing strategy is to serve all its loads out of inventory and meet any power deficits with short-term purchases, the incremental transmission and ancillary services costs are avoided when BPA makes firm power IP sales to the DSIs.

PS valued these avoided transmission and ancillary services costs using the same methodology used in the WP-10 rate proceeding to establish the total costs and risks associated with PS' inventory of transmission products and services. In these computations, both fixed, take-or-pay costs and variable incremental transmission and ancillary service costs were computed under 3,500 load and resource conditions for each month. Incremental transmission and ancillary services costs were computed by comparing the amount of surplus energy available to the monthly excess amount of firm transmission products in the PS inventory. Tariff costs established by BPA's Transmission Services organization were applied to the amount of surplus energy in excess of the PS transmission products inventory. Total monthly transmission and ancillary services costs were computed assuming no service to the DSI and DSI service of 372 aMW.[8] The average total monthly expense values of the 3,500 games were computed with and without service to the DSI and the differences were taken to determine the avoided PS transmission and ancillary services costs when PS makes these 372 aMW of IP sale(s) to the DSIs. For purposes of this analysis, Alcoa has been allotted 76.6% of this PS benefit in each month as illustrated in Table 5b below. This percent allotment is the result of the proportion of the megawatt amounts in the Block Contract, and as depicted in Table 1 above, as compared to the 372 aMW forecasted for all DSI customers.

[7] Refer to section 4 of the *Revenue Requirement Study*, WP-10-FS-BPA-02 and section 2.4 of the *Risk Analysis and Mitigation Study* in the WP-10 rate proceeding.

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

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

Month	Month ($)	Proportional Month ($)	Cumulative ($)
Dec-09	$149,883	$114,829	$114,829
Jan-10	$411,830	$315,515	$430,344
Feb-10	$323,594	$247,915	$678,259
Mar-10	$427,273	$327,346	$1,005,605
Apr-10	$546,922	$419,013	$1,424,617
May-10	$797,099	$610,680	$2,035,297
Jun-10	$706,870	$541,554	$2,576,851
Jul-10	$568,866	$435,825	$3,012,676
Aug-10	$127,860	$97,958	$3,110,634
Sep-10	$44,322	$33,956	$3,144,590
Oct-10	$39,191	$30,025	$3,174,616
Nov-10	$73,161	$56,051	$3,230,667
Dec-10	$150,605	$115,383	$3,346,050
Jan-11	$417,282	$319,692	$3,665,742
Feb-11	$318,185	$243,771	$3,909,512
Mar-11	$412,095	$315,718	$4,225,230
Apr-11	$492,378	$377,225	$4,602,455
May-11	$765,645	$586,583	$5,189,038
Jun-11	$669,032	$512,565	$5,701,603

Demand Shift

When BPA serves the DSI loads – including Alcoa – and they operate – as opposed to not operating if BPA does not sell to them – all of BPA's surplus sales realize increased revenues because the mean value of prices for electricity in Western power markets are higher than they would otherwise be had the DSI loads not consumed electricity from Western power markets. BPA has forecasted these increased revenues by reducing loads in the PNW by 372 aMW in each month for each of the 3,500 games AURORA simulated for the forecast used in Table 3 above. This lowered the mean price forecast by a 12-month average of $0.29 per MWh and by $0.41 per MWh for fiscal years 2010 and 2011 respectively.[9] The monthly difference resulting from this lower mean price forecast was then multiplied by BPA's monthly surplus energy from the WP-10 rate proceeding to determine the increased revenues available to BPA's surplus sales when BPA makes an IP sale(s) to the DSIs – including the Block Contract with Alcoa. For the purposes of this analysis, Alcoa has been allotted 76.6% of this benefit to BPA in each month as illustrated in Table 5c below. This percent allotment is the result of the proportion of the megawatt amounts in the Block Contract, and as depicted in Table 1 above, as compared to the 372 aMW forecasted for all DSI customers.

[9] 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 ($)	Demand Shift Proportional Month ($)	Demand Shift Cumulative ($)
Dec-09	$39,719	$30,430	$30,430
Jan-10	$146,279	$112,069	$142,499
Feb-10	$181,585	$139,118	$281,616
Mar-10	$279,051	$213,789	$495,406
Apr-10	$428,356	$328,176	$823,582
May-10	$1,347,534	$1,032,385	$1,855,967
Jun-10	$900,404	$689,826	$2,545,793
Jul-10	$519,495	$398,000	$2,943,793
Aug-10	$32,901	$25,206	$2,968,999
Sep-10	($25,231)	($19,330)	$2,949,669
Oct-10	$1,755	$1,345	$2,951,014
Nov-10	($29,249)	($22,408)	$2,928,606
Dec-10	$38,606	$29,578	$2,958,183
Jan-11	$453,911	$347,754	$3,305,937
Feb-11	$295,680	$226,529	$3,532,466
Mar-11	$651,012	$498,759	$4,031,225
Apr-11	$619,527	$474,638	$4,505,863
May-11	$1,548,290	$1,186,190	$5,692,053
Jun-11	$1,222,884	$936,887	$6,628,940

Conclusion of Equivalent Benefits Test

The preceding analysis demonstrates how the projected revenues BPA recovers from the approximate 17-month IP sale to Alcoa (from December 22, 2009 through May 31, 2011) exceed by approximately $151,000 the forecasted revenues that BPA would otherwise obtain from the market. See Table 6 below. BPA's methodology for making this determination is based, to the extent possible, on modeling tools used in BPA's rate case. That process includes discovery, testimony, rebuttal testimony, and cross examination prior to a final determination by the Administrator. Further, the analysis is marked by thorough and thoughtful consideration of market fundamentals and other factors that insure the integrity of the results. BPA believes that it a reasonable assessment and that the concerns expressed in the comments have been fully considered and fairly evaluated.

TABLE 6 - BPA's Net Benefit after Adjustments

	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 ($)	Cumulative ($)
Dec-09	$1,551,791	$169,632	$114,829	$30,430	$602,156	$602,156
Jan-10	$1,320,127	$169,632	$315,515	$112,069	$1,917,343	$2,519,498
Feb-10	$1,084,809	$153,216	$247,915	$139,118	$1,625,058	$4,144,556
Mar-10	$857,010	$169,404	$327,346	$213,789	$1,567,549	$5,712,105
Apr-10	$315,027	$164,160	$419,013	$328,176	$1,226,376	$6,938,481
May-10	($57,003)	$169,632	$610,680	$1,032,385	$1,755,694	$8,694,175
Jun-10	($260,536)	$164,160	$541,554	$689,826	$1,135,004	$9,829,179
Jul-10	($343,859)	$169,632	$435,825	$398,000	$659,598	$10,488,777
Aug-10	($469,005)	$169,632	$97,958	$25,206	($176,210)	$10,312,567
Sep-10	($690,623)	$164,160	$33,956	($19,330)	($511,836)	$9,800,731
Oct-10	($1,685,916)	$169,632	$30,025	$1,345	($1,484,914)	$8,315,817
Nov-10	($1,754,514)	$164,388	$56,051	($22,408)	($1,556,483)	$6,759,334
Dec-10	($2,102,464)	$169,632	$115,383	$29,578	($1,787,872)	$4,971,462
Jan-11	($1,806,237)	$169,632	$319,692	$347,754	($969,159)	$4,002,303
Feb-11	($1,770,977)	$153,216	$243,771	$226,529	($1,147,461)	$2,854,842
Mar-11	($2,074,122)	$169,404	$315,718	$498,759	($1,090,241)	$1,764,601
Apr-11	($2,203,572)	$164,160	$377,225	$474,638	($1,187,549)	$577,052
May-11	($2,367,982)	$169,632	$586,583	$1,186,190	($425,577)	$151,475
Jun-11	($2,332,082)	$164,160	$512,565	$936,887	($718,470)	($566,996)

Attachment G

BPA's Prepared Materials from November 3, 2009

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

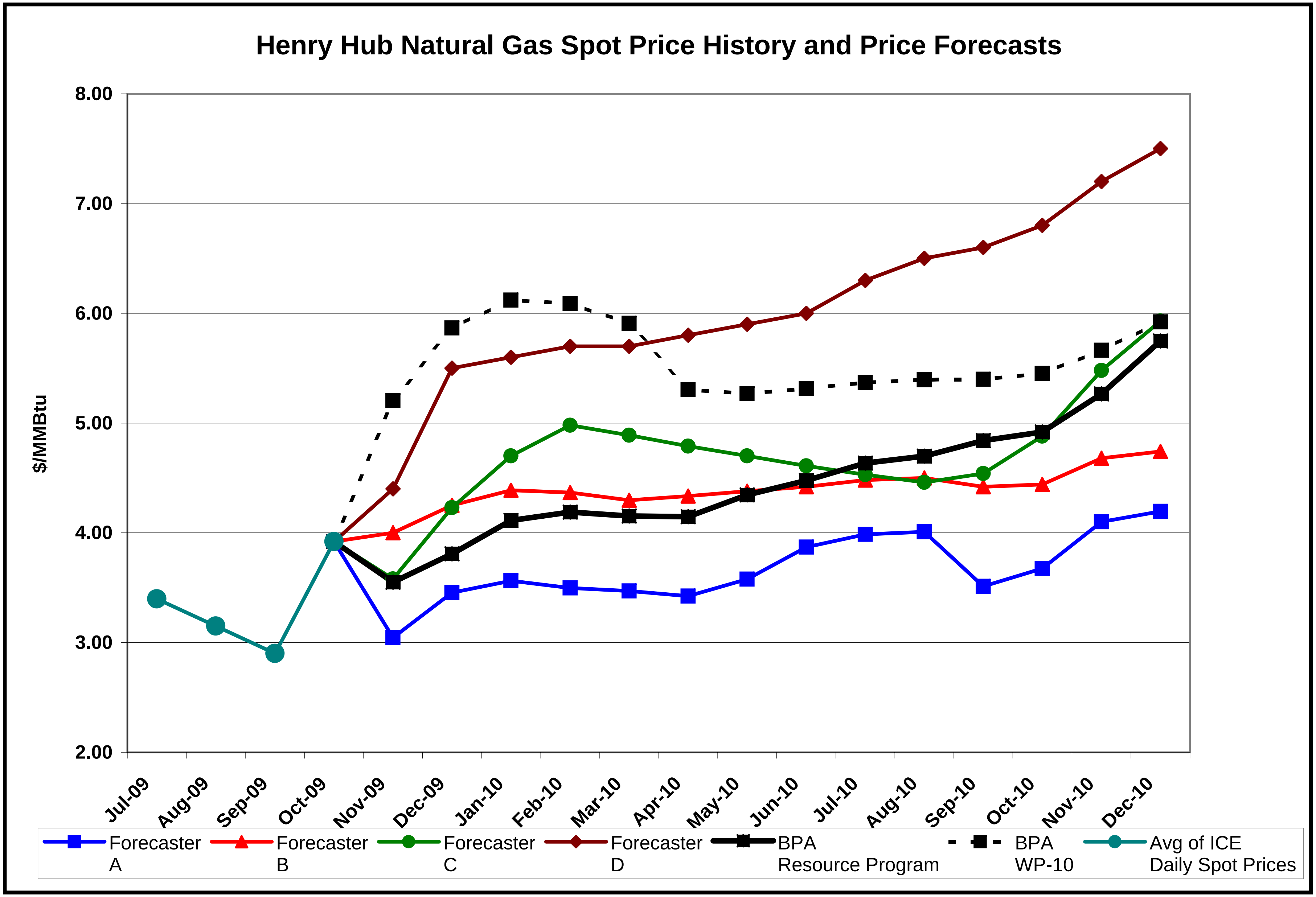
7/21/2009

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

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

7/21/2009

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


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

Attachment H

(referred to as Attachment H in footnote 39 on page 50 of the body of this Record of Decision)

BPA's Recreation of Snohomish Analysis

BPA's Re-creation of Snohomish Analysis

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

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

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

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

Figure 1 – Snohomish's Attachment A

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

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

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

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

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

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

Port Townsend Revenue Comparison Nov. 2009 - Dec. 2010

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

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

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

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

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

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

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

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

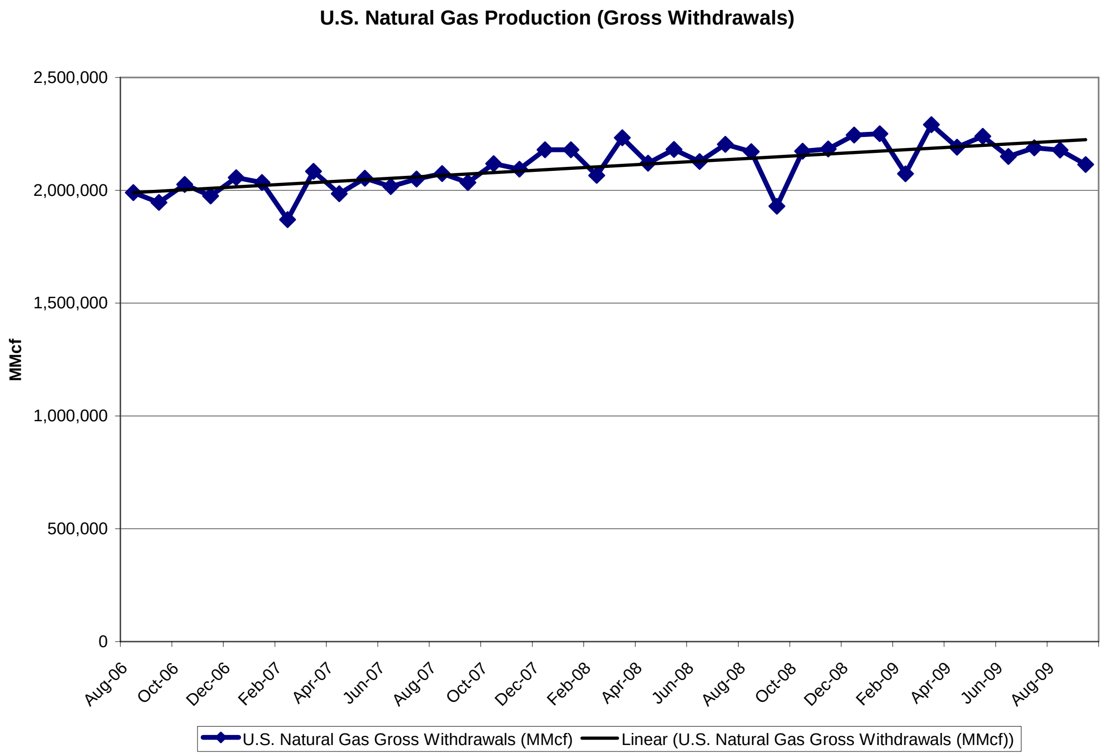
Attachment I

(referred to as Attachment H in footnote 41 on page 56 of the body of this Record of Decision)

Natural Gas Statistics

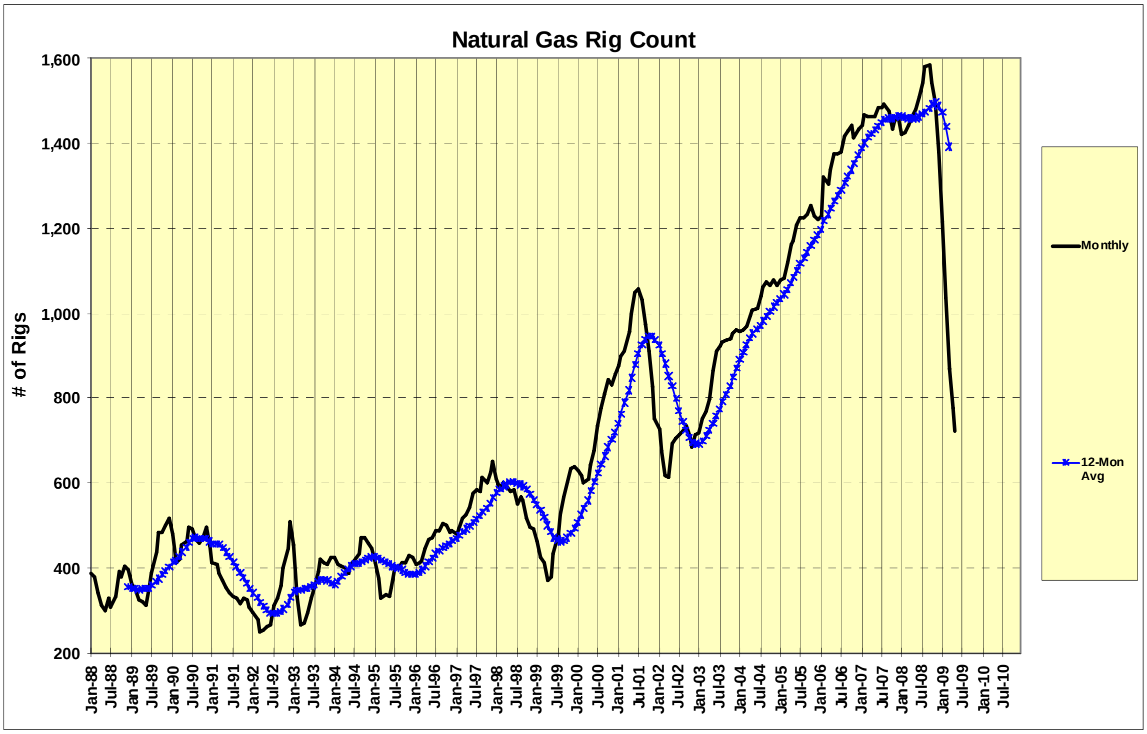
Natural Gas Statistics

Figure 1 – Natural Gas Production



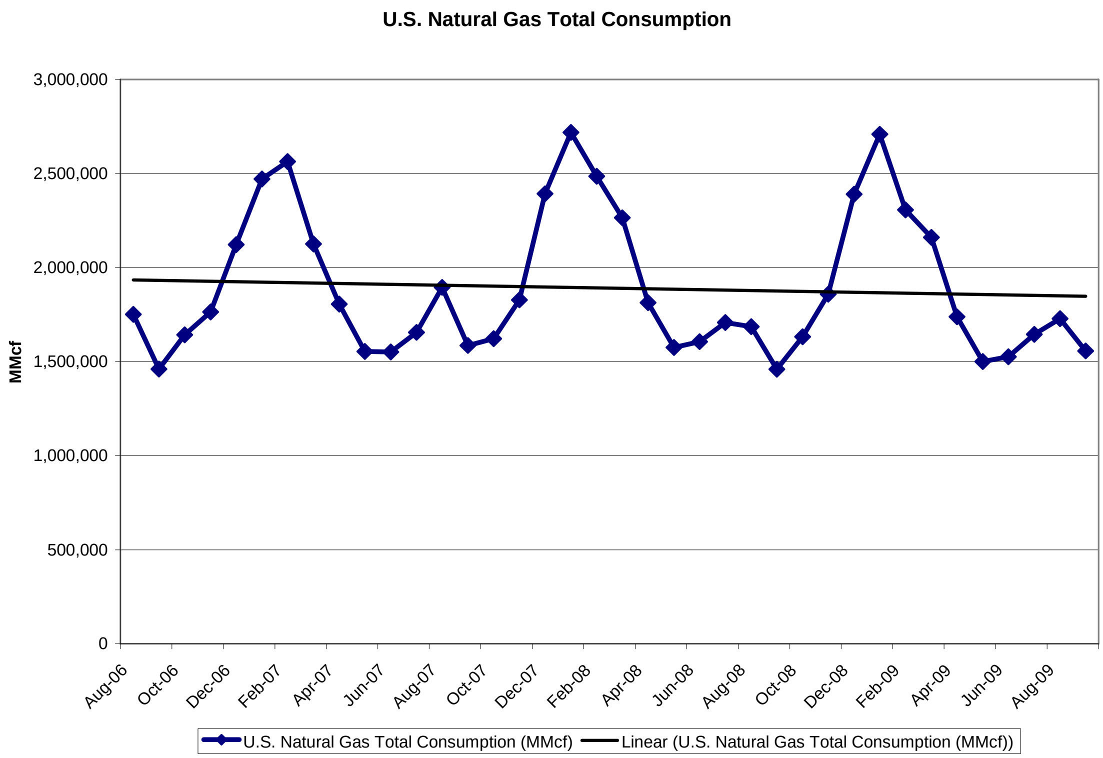
Source: United States Department of Energy, Energy Information Administration, released November 30, 2009.

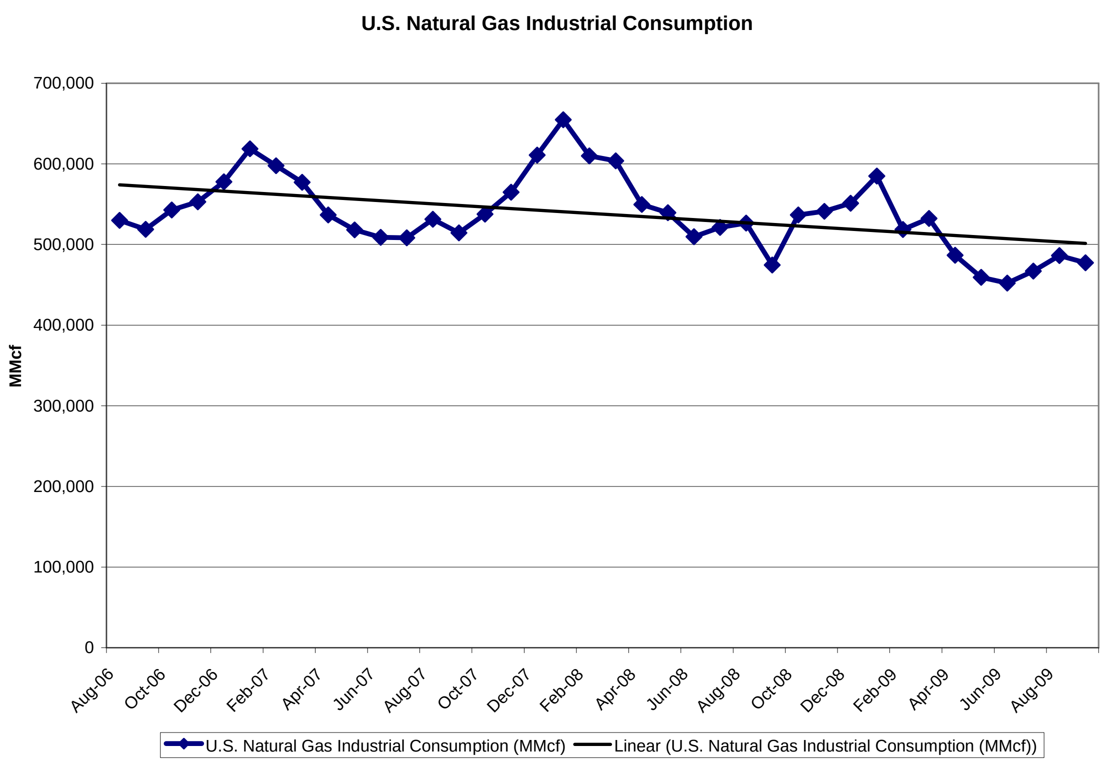
Figure 2 – Natural Gas Rig Count



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

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





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

Figure 4 – Natural Gas Storage

Weekly Natural Gas Storage Report

Released: December 17, 2009 at 10:30 A.M. (eastern time) for the Week Ending December 11, 2009.
Next Release: December 24, 2009

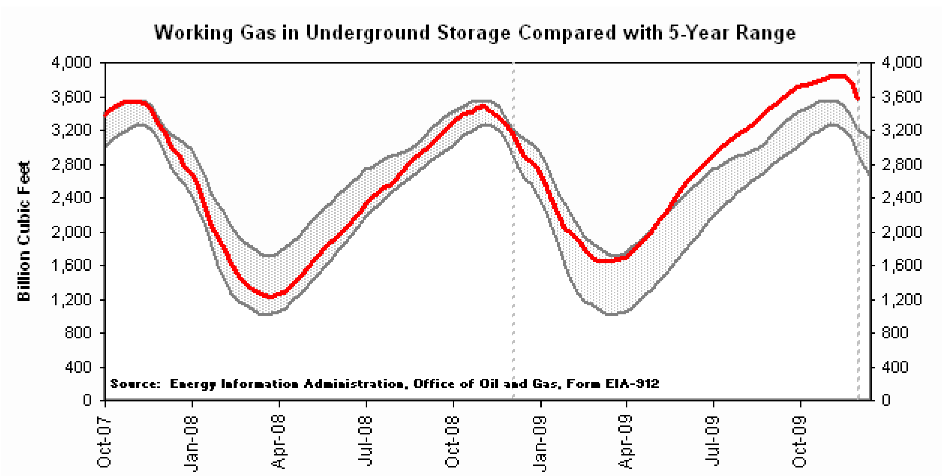
Working Gas in Underground Storage, Lower 48

other formats: Summary TXT CSV

Region	Stocks in billion cubic feet (Bcf)			Historical Comparisons			
				Year Ago (12/11/08)		5-Year (2004-2008) Average	
	12/11/09	12/04/09	Change	Stocks (Bcf)	% Change	Stocks (Bcf)	% Change
East	1,968	2,061	-93	1,793	9.8	1,789	10.0
West	478	517	-39	456	4.8	421	13.5
Producing	1,120	1,195	-75	936	19.7	923	21.3
Total	**3,566**	**3,773**	**-207**	**3,185**	**12.0**	**3,133**	**13.8**

Notes and Definitions

Summary
Working gas in storage was 3,566 Bcf as of Friday, December 11, 2009, according to EIA estimates. This represents a net decline of 207 Bcf from the previous week. Stocks were 381 Bcf higher than last year at this time and 433 Bcf above the 5-year average of 3,133 Bcf. In the East Region, stocks were 179 Bcf above the 5-year average following net withdrawals of 93 Bcf. Stocks in the Producing Region were 197 Bcf above the 5-year average of 923 Bcf after a net withdrawal of 75 Bcf. Stocks in the West Region were 57 Bcf above the 5-year average after a net drawdown of 39 Bcf. At 3,566 Bcf, total working gas is above the 5-year historical range.



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

Source: United States Department of Energy, Energy Information Administration, December 17, 2009.

Attachment J

(referred to as attached on page 63
of the body of this Record of Decision)

Letter from Alcoa requesting Increased to 320 aMW

ALCOA

Alcoa Primary Metals
Intalco Works
4050 Mountain View Road
P.O. Box 937
Ferndale, WA 98248 USA
Tel: 1 360 384 7061
Fax:1 360 384 6185

December 15, 2009

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

Re: Power Sales Agreement, Contract No. 10PB-12175

Dear Allen Burns;

Enclosed are the signed copies of the POWER SALES AGREEMENT, Contract No. 10PB-12175 as referenced in your correspondence dated December 14, 2009. Also enclosed is a formal request for Increased Firm Power Supply.

We look forward to working with BPA in the future.

Sincerely,

Mike Rousseau

Mike Rousseau
Plant Manager
Alcoa Intalco Works

ALCOA

December15, 2009

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

Re: Increase in Firm Power Supply

Dear Allen:

Pursuant to Section 5.2 of the POWER SALES AGREEMENT to be executed by the BONNEVILLE POWER ADMINISTRATION and ALCOA INC, upon execution, Alcoa requests an increase in Firm Power from 285 aMW to 320 aMW for the balance of the Initial Period or Extended Initial Period. As contemplated in Section 5.2, Alcoa has attached to this letter a schedule, by month, of Alcoa's proposed operating levels to achieve such Firm Power increase.

Sincerely,

Mike Rousseau

Mike Rousseau
Plant Manager
Alcoa Intalco Works

Schedule of Operating Levels

Month	Firm Power Load
December 2009	285 aMW
January 2010	300 aMW
February 2010	315 aMW
March 2010	320 aMW