Thermal Resource Data
Used in 2011 IRP Aurora Analysis

Unit	Nameplate Rating (MW)	Ownership Share (%)	Minimum Load (MW)	Min. Load IPCo Share (MW)	Full Load Heat Rate (Btu/kWh)
Bridger 1	540	33%	216	71	10,325
Bridger 2	540	33%	216	72	10,325
Bridger 3	540	33%	216	72	10,325
Bridger 4	508.5	33%	203.4	68	10,325
Boardman	556	10%	222.4	22	9,840
Valmy 1	254	50%	101.6	51	9,721
Valmy 2	267	50%	106.8	53	9,721
Danskin 1	170	100%	0	0	9,766
Danskin 2	49	100%	0	0	11,358
Danskin 3	49	100%	0	0	11,358
Bennett Mtn	170	100%	0	0	10,100
Langley Gulch **	306.8	100%	204	204	6,745

** - minimum load for Langley Gulch in Aurora varies by month based on ambient temperature - annual average of the monthly values is used for this example.

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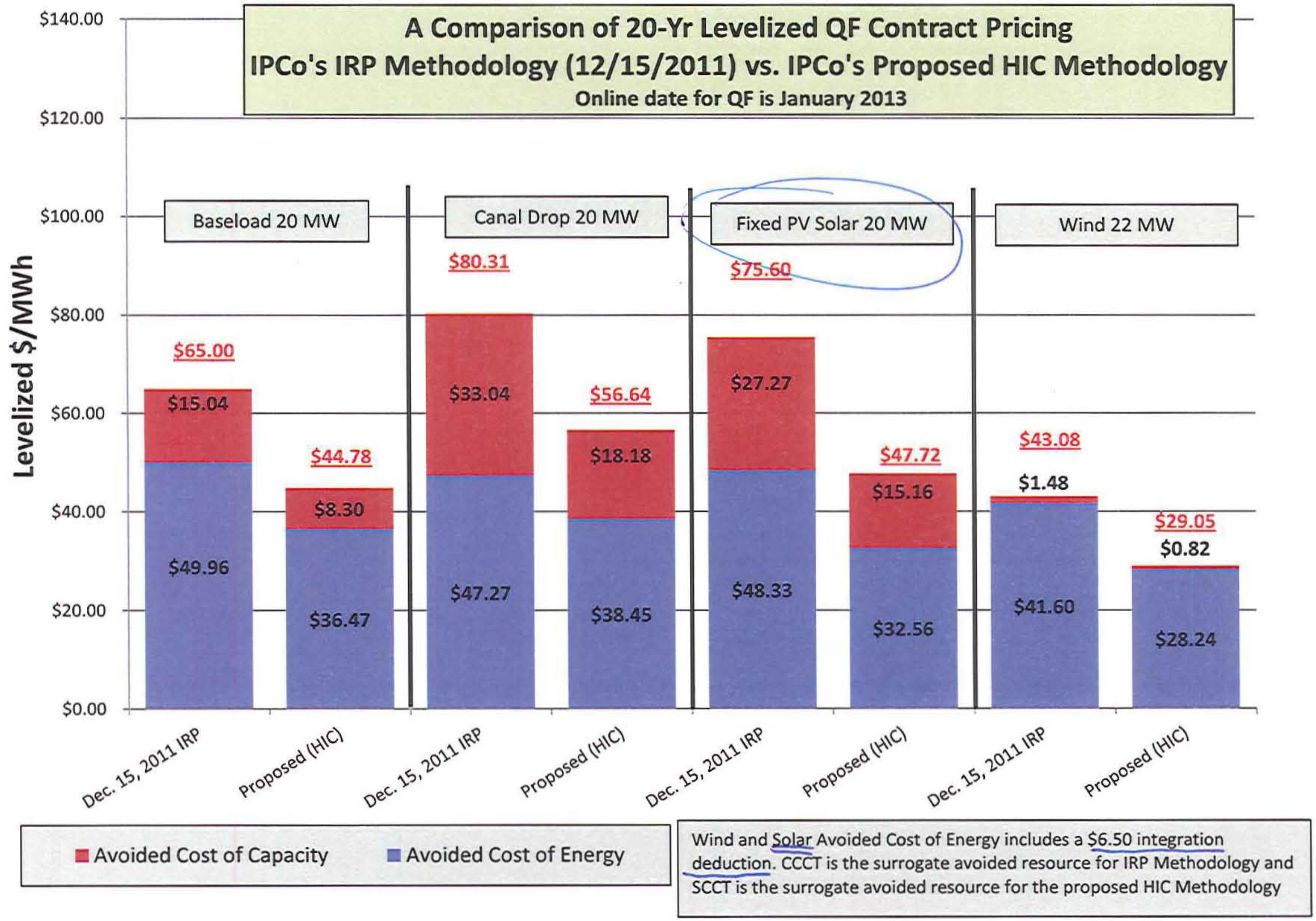

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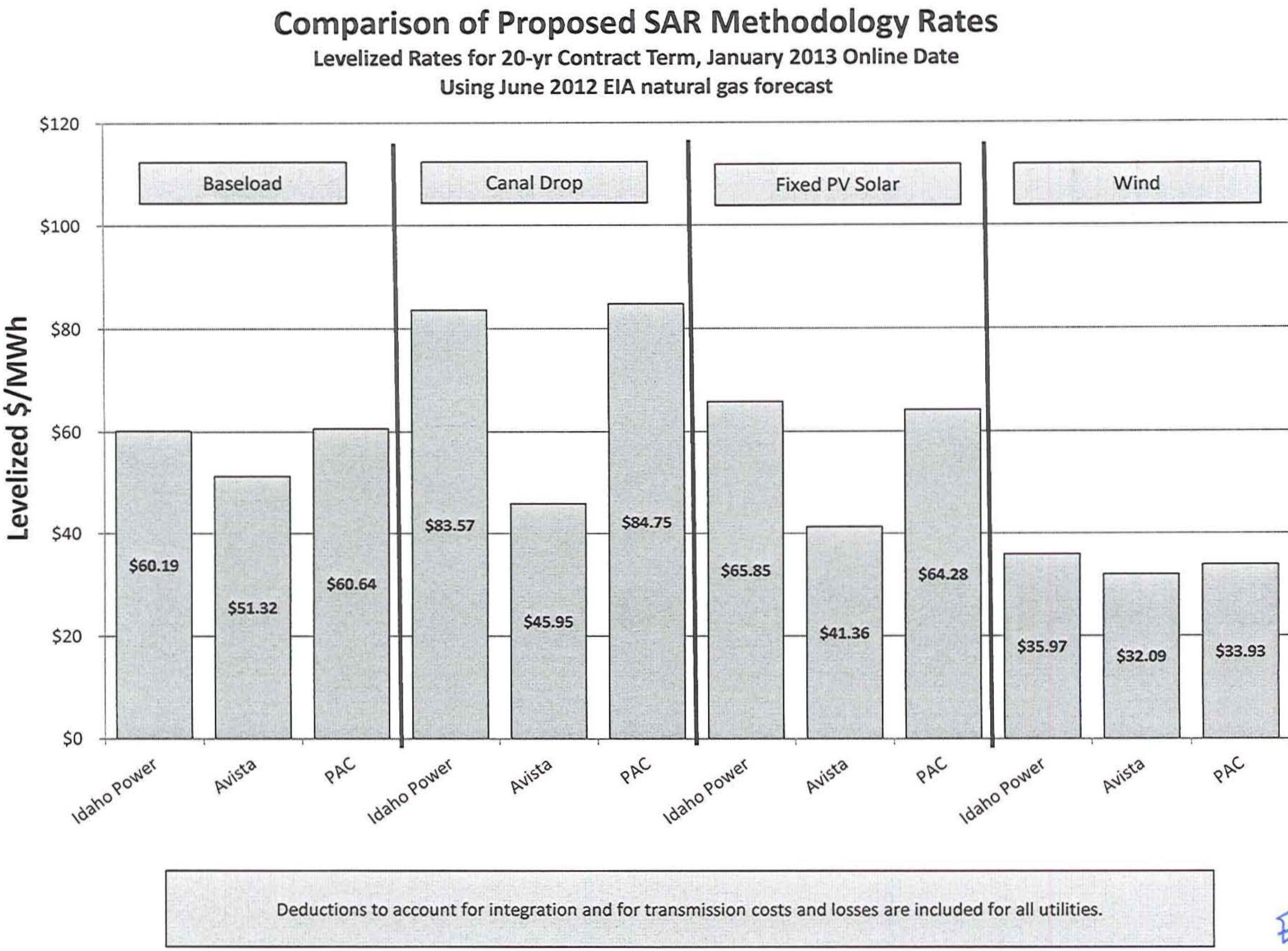

EXHIBIT
replacement 306

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE LANGLEY GULCH POWER PLANT	)))))	**CASE NO. IPC-E-09-03** **ORDER NO. 30892**

On March 6, 2009, Idaho Power Company (Idaho Power; Company) filed an Application with the Idaho Public Utilities Commission (Commission; IPUC) for a Certificate of Public Convenience and Necessity (Certificate; CPCN) authorizing construction of the Langley Gulch Power Plant (Project) and inclusion of the Project in the Company's rate base. *Idaho Code* § 61-526, -528; RP 112. An electrical corporation is prohibited from beginning the construction of a generating plant without having first obtained from the Commission a certificate that the present or future public convenience and necessity require or will require such construction. *Idaho Code* § 61-526. The Company further requests that the Commission include in its Order issuing a Certificate cost recovery and ratemaking assurances. *Idaho Code* § 61-541.

On March 19, 2009, the Commission issued a Notice of Application, Intervention Deadline and Prehearing Conference. Intervention was granted to the Industrial Customers of Idaho Power (ICIP); Invenergy Thermal Development LLC; Idaho Irrigation Pumpers Association, Inc. (IIPA); Snake River Alliance (SRA); and Idaho Conservation League (ICL). Following the April 15, 2009 prehearing conference Invenergy Thermal Development LLC withdrew and the following additional parties were admitted as intervenors: Northwest & Intermountain Power Producers Coalition (NIPPC) and Community Action Partnership Association of Idaho (CAPAI). An evidentiary and technical hearing was held in Boise on July 14-16, 2009. A public hearing was held the evening of July 14. The deadline for filing written comments was July 24. The deadline for post-hearing filings by the parties was July 31, 2009.

The Commission in this Order grants a Certificate of Convenience and Necessity authorizing the construction of Langley Gulch and provides related cost recovery and ratemaking assurances. *Idaho Code* § 61-541. We deny Intervenors' Motion for Stay and grant intervenor funding awards to the Community Action Partnership Association of Idaho, the Idaho Conservation League and the Idaho Irrigation Pumpers Association, Inc. *Idaho Code* § 61-617A.

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either cash flow or imputed debt that would impact the Company's financial rates. Tr. p. 831.

- It is incongruous that the Company would stress the need to issue its CPCN under non-traditional ratemaking procedures in order to finance the project and yet not to have considered financial implications in the scoring and selection process. Tr. p. 831.

- Rejects the Company's contention that imputed debt is a measure of financial risk shifted to a utility when it enters into a PPA or TA. Citing Standards & Poor's Opinion that a PPA is not the same thing as actual debt; debt-like-characteristics is not the same as debt. All debt is not created equal. Tr. pp. 833-836.

NIPPC offers as an example of competitive bidding guidelines those adopted by the Oregon Commission. Exh. 702.

Commission Findings

Once it determined a 2012 need for a baseload resource, Idaho Power retained a third-party consultant and issued a Request for Proposals. The RFP process was criticized by nearly all parties to the case, some more stridently than others. While we find that the process could have been more transparent, that better guidelines could have been established, that evaluation criteria could have better explained, that the third-party consultant could have brought more value to the process by performing all the tasks identified in the RFP, and that the total universe of potential bidders was perhaps not realized, we find that the RFP process was nevertheless adequate. Based on the evidence presented, we cannot conclude that a lower price and better project would have resulted if the RFP was better designed and implemented. What is instead apparent is that the RFP participants were sophisticated bidders and that the short list of projects were all competitive.

The Company is not foreclosed from including a self-build option in an RFP. Its obligation to provide electric service and its decision to bid a self-build alternative is a rational basis for lining up an equipment supplier in advance of its application to the Commission. Idaho Power in this RFP was not the only bidder to bring turbines to the table. The Company should, however, be concerned about perception that the third-party consultant was directed by the Company and there was a bias in the selection process. The actual and perceived flaws in the RFP process, we find, while not fatal to the Company's resource selection, clearly demonstrate a need for a separate proceeding to consider RFP competitive bidding rules and guidelines. We

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determined by a formula that ranges from $16 to $29 per megawatt-hour in 1987-year constant dollars.

The second provision provides BPA approximately 32 aMW of return energy at a cost equal to the actual operating cost of the Company's highest-cost resource. A further discussion of this obligation, and how Avista plans to account for it, is under the Planning Margin heading of this chapter.

Table 2.5: Large Contractual Rights and Obligations

Contract	Type	End Date	Winter Capacity (MW)	Summer Capacity (MW)	2012 Est. Annual Energy (aMW)
Canadian Entitlement	Sale	n/a	8	8	5
Clearwater	PURPA	06/2013	75	75	52
Douglas Settlement	Purchase	09/2018	2	3	3
Lancaster	Purchase	10/2026	290	249	222
Nichols Pumping	Sale	n/a	7	7	7
PGE Capacity Exchange	Exchange	12/2016	150	150	0
Small Power	PURPA	varies	2	1	2
Stateline	Purchase	03/2014	0	0	9
Stimson Lumber	Purchase	09/2011	4	5	4
Upriver (net load)	Purchase	12/2011	8	-1	6
WNP-3	Purchase	06/2019	82	0	42
Total			**628**	**497**	**352**

Reserve Margins

Planning reserves accommodate situations when loads exceed and/or resource outputs are below expectations due to adverse weather, forced outages, poor water conditions, or other contingencies. There are disagreements within the industry on reserve margin levels utilities should carry. Many disagreements stem from system differences, such as resource mix, system size, and transmission interconnections

Reserve margins, on average, increase customer rates when compared to resource portfolios without reserves, because of the cost of carrying additional generating capacity that is rarely used. Reserve resources have the physical capability to generate electricity, but high operating costs limit their economic dispatch and revenues to offset purchase costs.

Avista Planning Margin

Avista retains two planning margin targets—capacity and energy. Capacity planning is a traditional metric ensuring that utilities can meet peak loads at times of system strain, and cover variability inherent in their generation resources with unpredictable fuel supplies, such as wind and hydro, and varying loads.

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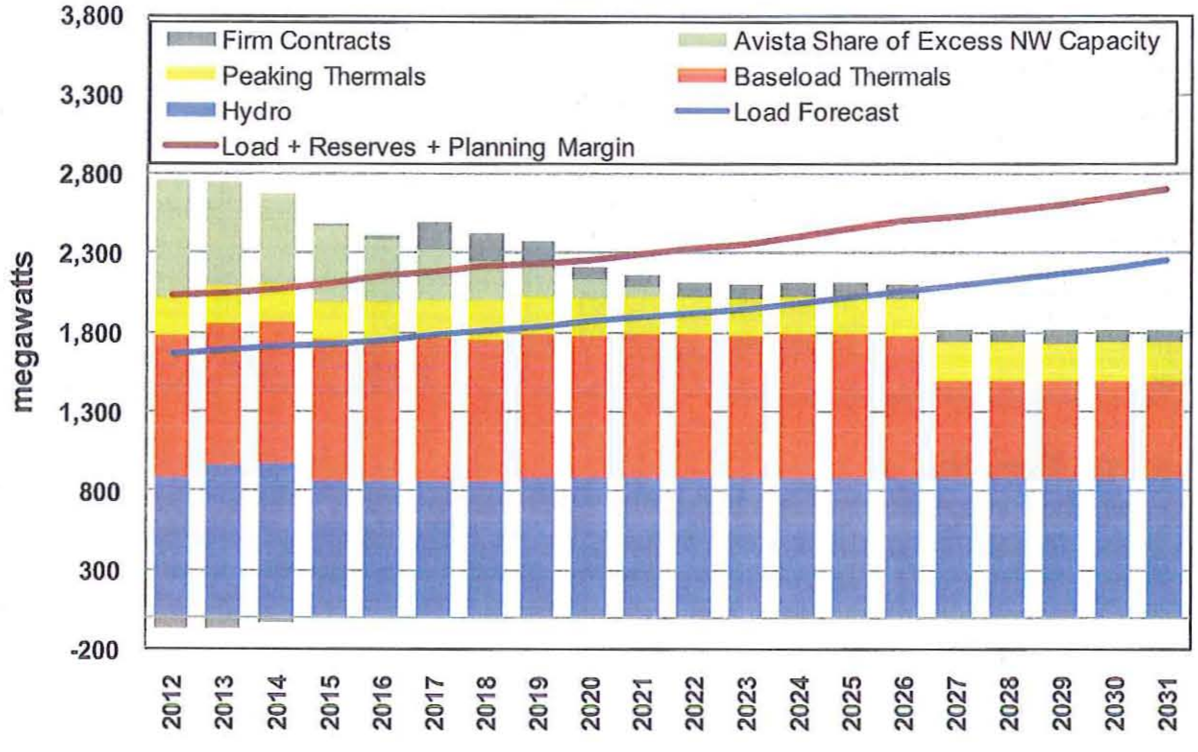
Capacity Planning

Avista plans for peak load events using the regional standard of an 18-hour peak event covering six hours each day for three consecutive days. Further, the IRP uses a planning margin level approximating the Northwest Power and Conservation Council's targets of 23 percent in the winter and 24 percent in the summer. Avista first estimates operating reserve requirements for on-system generation, load regulation, and wind integration. It then adds a planning margin of 15 percent to summer peak load and 14 percent to winter peak load. Adjustments to the net position include market purchases when surplus capacity exists in the Northwest, as represented by the green bars.[7] The planning margin equals 233 MW in 2012. Additional detail is in Appendix A. Figure 2.14 illustrates the winter peak position and Figure 2.15 shows the summer peak position.

Figure 2.14: Winter 18-Hour Capacity Load and Resources



[7] Avista relied on work by the Northwest Power and Conservation Council in its Resource Adequacy Forum exercises to determine the level of surplus summer energy and capacity. Reliance is limited to Avista's prorated share of regional load. See http://www.nwcouncil.org/energy/resource/Adequacy%20Assessment%2070908.xls. NPCC surplus estimates phase out over 10 years starting in 2013 by reducing its surplus by 10 percent, the 2014 surplus by 20 percent, the 2015 surplus by 30 percent, and so on. The phase out reflects Avista's opinion that outer-year surpluses might not be available for various reasons, including unanticipated load growth, the retirement of existing resources, or transmission interconnections enabling the export of more generation outside of the Northwest.

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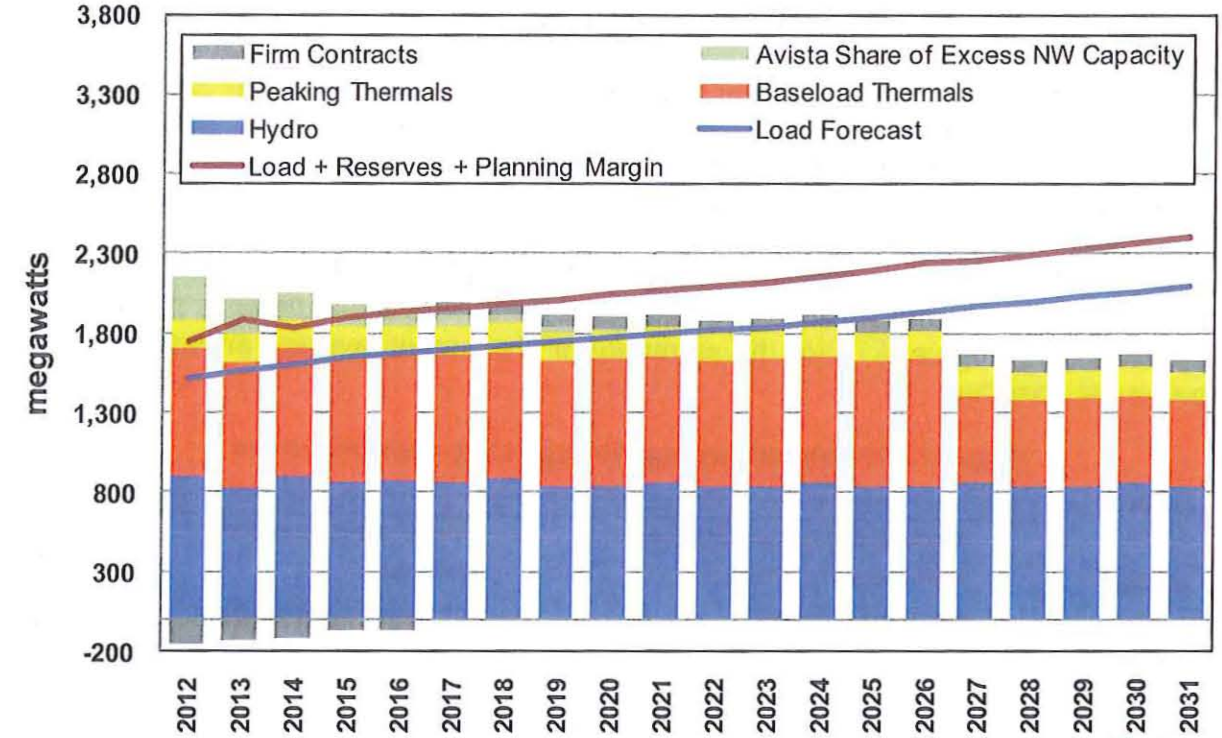
Figure 2.15: Summer 18-Hour Capacity Load and Resources



Energy Planning

For energy planning, resources must be adequate to meet customer requirements even where loads are high for extended periods or an outage limits the output of a resource. Extreme weather conditions can change monthly energy obligations by up to 30 percent. Where generation capability is not adequate to meet these variations, customers and the utility must rely on the volatile short-term electricity market. In addition to load variability, a planning margin accounts for variations in hydroelectricity generation.

As with capacity planning, there are differences in regional opinion on a proper method for establishing resource planning margins. Many utilities in the Northwest base their planning on the amount of energy available during the critical water period of 1936/37.[8] The critical water year of 1936/37 is low on an annual basis, but it is not necessarily low in every month. The IRP could target resource development to reach a 99 percent confidence level on being able to deliver energy to its customers, and it would significantly decrease the frequency of its market purchases. However, this strategy requires investments in approximately 200 MW of generation in additional to the margins included in Expected Case of the IRP. Such expenditure to support this high level of reliability would put upward pressure on retail rates for a modest benefit. Avista instead targets a 90 percent monthly energy planning margin confidence interval based on load hydroelectricity variability. In other words, there is a 10 percent chance of needing to purchase energy from the market in any given month over the IRP

[8] The critical water year represents the lowest historical generation level in the streamflow record.

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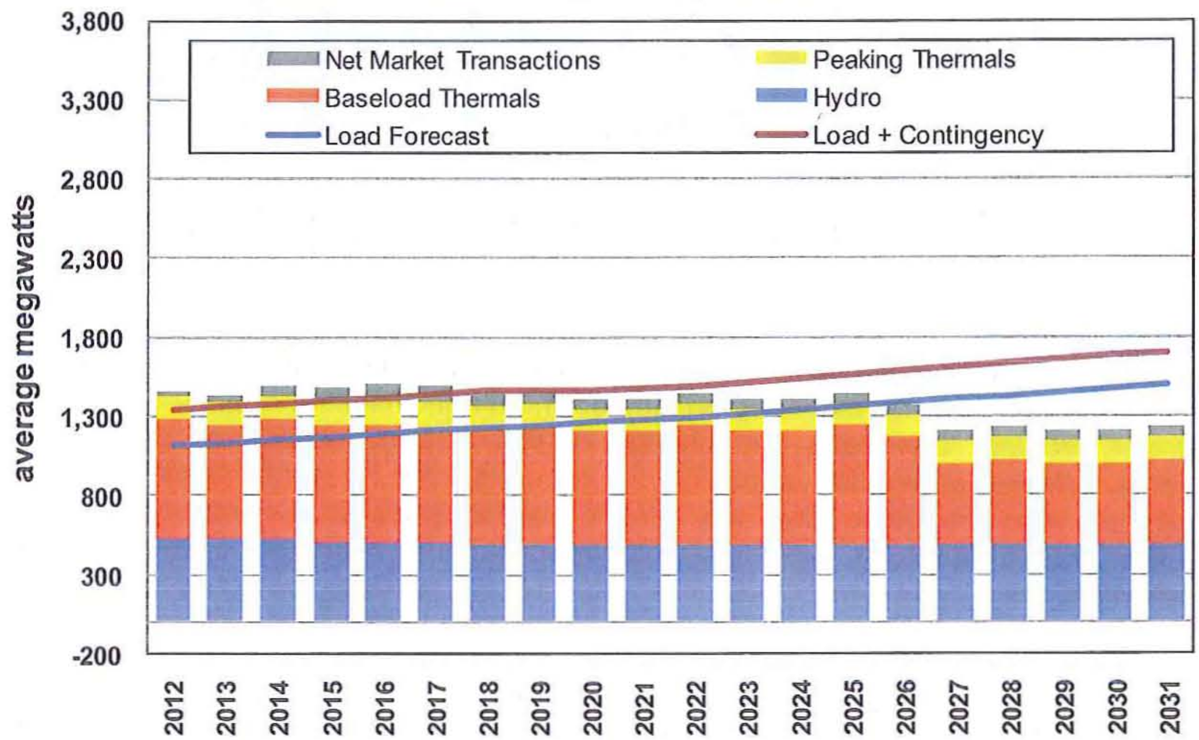
timeframe, but on average, the utility would have the ability to meet all of its energy requirements and be selling electricity into the marketplace.

Beyond load and hydroelectricity variability, Avista's WNP-3 contract with BPA contains supply risk. The contract includes a return energy provision in favor of BPA that can equal 32 aMW annually. Under adverse market conditions BPA almost certainly would exercise its rights. BPA last exercised its contract rights in 2001. To account for this contract risk, the energy planning margin is increased by 32 aMW until the contract expires in 2019. With the addition of WNP-3, load and hydroelectricity variability, the total energy planning margin equals 228 aMW in 2012. Additional detail is contained in Appendix A. See Figure 2.16 for the summary of the annual average energy load and resource net position.

Figure 2.16: Annual Average Energy Load and Resources



Loss of Load Analysis

In the Northwest, loss-of-load analysis tools help address the issue of how much planning margin is required. Typical results of these models are Loss of Load Probability (LOLP), Loss of Load Hours (LOLH), and Loss of Load Expectation (LOLE) measures. A reliable system has typically been defined as having no more than one interruption event in twenty years, or 5 percent. These analyses can be helpful, but usually have an inherent flaw due to the need to assume how much out-of-area generation is available for the study. Avista developed a loss of load analysis model to simulate reliability events due to poor hydro, forced outages, and extreme weather conditions on its system, finding that forced outages are the main driver of reliability events. Avista has robust transmission rights to the wholesale energy markets, but the

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amount of generation actually available for purchase from third parties is difficult to estimate in a model. To address this concern, a sophisticated regional model must estimate required regional planning margins. Avista will continue to monitor and contribute to such regional model development, with the intent of using the regional model when it becomes available.

Washington State Renewable Portfolio Standard

In the November 2006 general election, Washington State voters approved Citizens Initiative 937, now known as the Washington state Energy Independence Act. The initiative requires utilities with more than 25,000 customers to source 3 percent of their energy from qualified non-hydroelectric renewables by 2012, 9 percent by 2016, and 15 percent by 2020. Utilities also must acquire all cost effective conservation and energy efficiency measures. Even though Avista does not require any new generation resources to meet forecasted energy loads through 2019, this new law requires the Company to acquire additional qualified renewable generation, or renewable energy certificates (RECs), to meet the initiative's renewable goals. Table 2.6 at the end of this chapter details the forecast amount of RECs required to meet Washington state law, and the amount of qualifying resources has already in the generation portfolio. The sales forecast uses the current load forecast and does not include additional conservation as detailed in the Preferred Resource Strategy chapter. It also illustrates how the Company will maintain a REC reserve margin of approximately 10 aMW in 2016.

Resource Requirements

The resource requirements discussed in this section do not include additional energy efficiency acquisitions beyond what is in the load forecast. The Preferred Resource Strategy chapter discusses conservation beyond the assumptions contained in the load forecast. The following tables present loads and resources to illustrate future resource requirements.

During winter peak periods (Table 2.7), surplus capacity exists through 2019 after taking into account market purchases.[9] Without these purchases, a capacity deficit would exist in 2012. Avista believes that the present market can meet these minor winter capacity shortfalls and therefore will optimize its portfolio to postpone new resource investments for winter capacity until 2020.

The summer peak projection (Table 2.8) has lower loads than in winter, but resource capabilities are also lower due to lower hydroelectricity output and reduced capacity at natural gas-fired resources due to decreased performance during high-temperature events. The IRP shows persistent summer deficits throughout the 20-year timeframe, but regional surpluses are adequate to fill in these gaps. Many near-term deficits are from decreased hydroelectricity capacity during periods of planned maintenance and

[9] Avista relied on work by the Northwest Power and Conservation Council in its Resource Adequacy Forum exercises to determine the level of surplus summer energy and capacity. Reliance is limited to the Company's prorate share of regional load.

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upgrades. Taking into account regional surpluses, the load and resource balance is 54 MW short only in 2016. After 2016, when the Portland General Electricity capacity sale contract expires, the next capacity need is in 2019 at 98 MW.

The traditional measure of resource need in the region is the annual average energy position. The energy position is in Table 2.9. There is enough energy on an annual average basis to meet customer requirements until 2020, when the utility is short 49 aMW. Avista will require 112 aMW of new energy by 2025, and 475 aMW in 2031.

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Table 2.6: Washington State RPS Detail (aMW)

	On-line Year	Upgrade Energy	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
WA State Retail Sales Forecast			628	630	636	646	654	663	671	678	687	693	701	708	714	721	730	738	746	754	763	772	782	793
RPS %				0%	3%	3%	3%	3%	9%	9%	9%	9%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
REQUIRED RENEWABLE ENERGY					**19**	**19**	**19**	**20**	**59**	**60**	**61**	**61**	**104**	**105**	**106**	**107**	**108**	**109**	**110**	**111**	**112**	**114**	**115**	**117**
Renewable Resources																								
Purchased RECs				0	6	6	6	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long Lake 3	1999	2.2		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Little Falls 4	2001	0.6		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Cabinet 2	2004	2.9		3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Cabinet 3	2001	4.5		4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Cabinet 4	2007	2.0		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Noxon 1	2009	2.3		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Noxon 3	2010	1.9		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Noxon 2	2011	1.0		0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Noxon 4	2012	0.9		0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nine Mile	2012	3.7		0	0	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Total Qualifying Resources				***17***	***23***	***26***	***28***	***28***	***22***	***22***	***22***	***22***	***22***	***22***	***22***	***22***	***22***	***22***	***22***	***22***	***22***	***22***	***22***	***22***
NET REC POSITION				**17**	**5**	**7**	**8**	**8**	**(37)**	**(38)**	**(39)**	**(39)**	**(82)**	**(83)**	**(84)**	**(85)**	**(86)**	**(87)**	**(88)**	**(89)**	**(90)**	**(92)**	**(93)**	**(95)**
REC Bank																								
Previous Year Balance				0	17	21	26	28	28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REC's Required				0	(19)	(19)	(19)	(20)	(59)	(60)	(61)	(61)	(104)	(105)	(106)	(107)	(108)	(109)	(110)	(111)	(112)	(114)	(115)	(117)
REC's Generated/Purchased				17	23	26	28	28	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
Expired/Sold RECs					0	(2)	(7)	(8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NET REC BANK				**17**	**21**	**26**	**28**	**28**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
REC Reserve Requirement (95th PERCENTILE)																								
Load				0	1	1	1	1	3	3	3	3	5	5	5	5	5	5	5	5	5	5	6	6
Existing Hydro Upgrades				0	6	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Total REC Reserve Requirement				**0**	**7**	**8**	**8**	**8**	**10**	**10**	**10**	**10**	**12**	**12**	**12**	**12**	**12**	**12**	**13**	**13**	**13**	**13**	**13**	**13**
NET REC POSITION				**17**	**14**	**21**	**26**	**28**	**(20)**	**(48)**	**(49)**	**(50)**	**(94)**	**(95)**	**(96)**	**(97)**	**(98)**	**(99)**	**(101)**	**(102)**	**(103)**	**(105)**	**(106)**	**(108)**

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Table 2.7: Winter 18-Hour Capacity Position (MW)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
TOTAL LOAD OBLIGATIONS																				
Native Load	-1,661	-1,688	-1,704	-1,718	-1,751	-1,784	-1,814	-1,839	-1,866	-1,892	-1,919	-1,946	-1,982	-2,020	-2,062	-2,094	-2,131	-2,168	-2,208	-2,249
Firm Power Sales	-242	-242	-211	-158	-158	-8	-8	-7	-7	-7	-7	-7	-6	-6	-6	-6	-6	-6	-6	-6
Total Requirements	**-1,903**	**-1,930**	**-1,915**	**-1,876**	**-1,909**	**-1,792**	**-1,822**	**-1,846**	**-1,873**	**-1,899**	**-1,925**	**-1,953**	**-1,988**	**-2,027**	**-2,068**	**-2,101**	**-2,137**	**-2,174**	**-2,214**	**-2,255**
RESOURCES																				
Firm Power Purchases	175	175	175	175	175	175	174	173	90	90	90	90	90	90	90	90	90	90	90	90
Hydro Resources	880	955	965	854	854	865	861	889	881	889	889	881	889	889	881	889	889	881	889	889
Base Load Thermals	895	895	895	895	895	895	895	895	895	895	895	895	895	895	895	606	606	606	606	606
Wind Resources	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peaking Units	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242	242
Total Resources	**2,192**	**2,267**	**2,277**	**2,166**	**2,166**	**2,177**	**2,172**	**2,199**	**2,108**	**2,116**	**2,116**	**2,108**	**2,116**	**2,116**	**2,108**	**1,826**	**1,826**	**1,818**	**1,826**	**1,826**
Peak Position Before Reserves Planning	**289**	**337**	**362**	**290**	**256**	**385**	**350**	**353**	**236**	**217**	**191**	**155**	**127**	**89**	**40**	**-275**	**-311**	**-356**	**-388**	**-429**
RESERVE PLANNING																				
Required Operating Reserves	-162	-164	-163	-162	-165	-159	-161	-163	-165	-167	-173	-176	-180	-182	-186	-170	-170	-171	-172	-173
Available Operating Reserves	23	42	42	8	8	8	8	34	34	34	34	34	34	34	34	34	34	34	34	34
Planning Margin	-233	-236	-239	-240	-245	-250	-254	-258	-261	-265	-269	-272	-277	-283	-289	-293	-298	-304	-309	-315
Total Reserves Planning	**-372**	**-358**	**-360**	**-394**	**-402**	**-400**	**-407**	**-387**	**-392**	**-398**	**-408**	**-414**	**-423**	**-431**	**-441**	**-429**	**-434**	**-441**	**-447**	**-454**
Peak Position With Reserves Planning	**-83**	**-21**	**2**	**-105**	**-146**	**-15**	**-57**	**-34**	**-157**	**-181**	**-216**	**-259**	**-296**	**-342**	**-401**	**-704**	**-746**	**-796**	**-835**	**-883**
Planning Margin Before NW Market	**16%**	**20%**	**21%**	**16%**	**14%**	**22%**	**20%**	**21%**	**14%**	**13%**	**12%**	**10%**	**8%**	**6%**	**4%**	**-11%**	**-13%**	**-15%**	**-16%**	**-18%**
Avista Share of Excess NW Capacity	737	656	565	477	400	326	255	186	115	56	0	0	0	0	0	0	0	0	0	0
Peak Position With NW Market	**654**	**635**	**567**	**373**	**254**	**311**	**199**	**152**	**-42**	**-125**	**-216**	**-259**	**-296**	**-342**	**-401**	**-704**	**-746**	**-796**	**-835**	**-883**
Peak Position With NW Market	**55%**	**54%**	**51%**	**41%**	**35%**	**40%**	**34%**	**31%**	**21%**	**16%**	**12%**	**10%**	**8%**	**6%**	**4%**	**-11%**	**-13%**	**-15%**	**-16%**	**-18%**

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Table 2.8: Summer 18-Hour Capacity Position (MW)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
TOTAL LOAD OBLIGATIONS																				
Native Load	-1,514	-1,556	-1,597	-1,644	-1,673	-1,701	-1,727	-1,748	-1,771	-1,793	-1,815	-1,838	-1,868	-1,900	-1,937	-1,964	-1,995	-2,026	-2,059	-2,094
Firm Power Sales	-243	-218	-212	-159	-159	-9	-9	-8	-8	-8	-8	-8	-8	-7	-7	-7	-7	-7	-7	-7
Total Requirements	**-1,757**	**-1,774**	**-1,809**	**-1,804**	**-1,832**	**-1,710**	**-1,736**	**-1,756**	**-1,778**	**-1,800**	**-1,822**	**-1,846**	**-1,876**	**-1,908**	**-1,944**	**-1,971**	**-2,002**	**-2,033**	**-2,067**	**-2,102**
RESOURCES																				
Firm Power Purchases	85	85	85	85	85	85	85	83	83	82	82	82	82	82	82	82	82	82	82	82
Hydro Resources	900	819	902	859	866	864	885	833	840	859	833	840	859	833	840	859	833	840	859	833
Base Load Thermals	799	799	799	799	799	799	799	799	799	799	799	799	799	799	799	551	551	551	551	551
Wind Resources	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peaking Units	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176
Total Resources	**1,960**	**1,880**	**1,962**	**1,919**	**1,926**	**1,924**	**1,945**	**1,891**	**1,897**	**1,916**	**1,891**	**1,896**	**1,916**	**1,890**	**1,896**	**1,668**	**1,642**	**1,648**	**1,668**	**1,642**
Peak Position Before Reserves Planning	**203**	**106**	**152**	**116**	**94**	**214**	**209**	**135**	**119**	**116**	**68**	**51**	**41**	**-18**	**-48**	**-304**	**-361**	**-385**	**-399**	**-460**
RESERVE PLANNING																				
Required Operating Reserves	-153	-157	-159	-160	-162	-155	-157	-160	-161	-163	-165	-167	-169	-171	-172	-157	-156	-157	-158	-158
Available Operating Reserves	155	66	171	159	159	159	161	158	158	161	158	158	161	158	158	161	158	158	161	158
Planning Margin	-227	-233	-240	-247	-251	-255	-259	-262	-266	-269	-272	-276	-280	-285	-290	-295	-299	-304	-309	-314
Total Reserves Planning	**-227**	**-325**	**-240**	**-248**	**-255**	**-255**	**-259**	**-264**	**-269**	**-271**	**-279**	**-285**	**-289**	**-298**	**-304**	**-295**	**-299**	**-304**	**-309**	**-314**
Peak Position With Reserves Planning	**-24**	**-220**	**-87**	**-132**	**-161**	**-41**	**-50**	**-129**	**-150**	**-155**	**-211**	**-234**	**-249**	**-316**	**-352**	**-599**	**-660**	**-689**	**-708**	**-774**
Planning Margin Before NW Market	**20%**	**10%**	**18%**	**15%**	**14%**	**22%**	**21%**	**17%**	**16%**	**15%**	**12%**	**11%**	**11%**	**7%**	**6%**	**-7%**	**-10%**	**-11%**	**-12%**	**-14%**
Avista Share of Excess NW Capacity	275	221	178	141	107	78	52	31	10	3	0	0	0	0	0	0	0	0	0	0
Peak Position With NW Market	**251**	**1**	**91**	**9**	**-54**	**36**	**2**	**-98**	**-140**	**-152**	**-211**	**-234**	**-249**	**-316**	**-352**	**-599**	**-660**	**-689**	**-708**	**-774**
Peak Position With NW Market	**36%**	**22%**	**28%**	**23%**	**20%**	**26%**	**24%**	**18%**	**16%**	**16%**	**12%**	**11%**	**11%**	**7%**	**6%**	**-7%**	**-10%**	**-11%**	**-12%**	**-14%**

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Table 2.9: Average Annual Energy Position (aMW)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
TOTAL LOAD OBLIGATIONS																				
Native Load	-1,109	-1,131	-1,148	-1,165	-1,186	-1,209	-1,228	-1,244	-1,260	-1,277	-1,293	-1,310	-1,333	-1,357	-1,386	-1,406	-1,429	-1,452	-1,477	-1,502
Firm Power Sales	-140	-127	-109	-58	-58	-6	-6	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
Total Requirements	**-1,249**	**-1,258**	**-1,258**	**-1,223**	**-1,244**	**-1,215**	**-1,234**	**-1,249**	**-1,266**	**-1,282**	**-1,298**	**-1,316**	**-1,338**	**-1,362**	**-1,391**	**-1,411**	**-1,434**	**-1,457**	**-1,482**	**-1,507**
RESOURCES																				
Firm Power Purchases	163	164	163	165	163	112	111	91	66	66	65	65	65	65	65	65	65	65	65	65
Hydro	522	525	527	495	495	495	490	481	481	481	481	481	481	481	481	481	481	481	481	481
Base Load Thermals	755	714	751	744	746	741	724	758	721	721	758	721	721	758	684	515	541	515	515	541
Total Resources	**1,441**	**1,403**	**1,442**	**1,405**	**1,404**	**1,348**	**1,325**	**1,330**	**1,268**	**1,268**	**1,304**	**1,266**	**1,267**	**1,304**	**1,229**	**1,060**	**1,087**	**1,060**	**1,060**	**1,087**
Energy Position Before Contingency Planning	191	145	184	182	161	133	91	81	2	-14	6	-49	-71	-58	-162	-351	-347	-397	-421	-421
CONTINGENCY PLANNING																				
Peaking Resources	153	153	153	138	153	154	153	147	146	145	147	146	145	147	146	145	147	146	145	147
Contingency	-228	-229	-230	-231	-232	-233	-233	-216	-197	-198	-198	-199	-200	-201	-202	-203	-204	-205	-206	-200
Energy Position With Contingency Planning	116	69	108	89	82	54	11	13	-49	-67	-46	-103	-126	-112	-218	-408	-405	-456	-482	-475
Energy Margin	28%	24%	27%	26%	25%	24%	20%	18%	12%	10%	12%	7%	6%	7%	-1%	-15%	-14%	-17%	-19%	-18%

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Simplot, Exergy, Clearwater
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Pacific Northwest Regional Resource Adequacy Assessment

Energy Load/Resource Balance Assessment **2011 Bal = 2584** **Threshold = 0**

NWPCC

May 28, 2008 **Last Update**

Summary	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Ann
Net Demand	21040	21096	22934	24769	25730	24734	23376	21858	21243	22170	22911	22793	**22882**
Net Resources	23599	24143	28231	28887	26262	25611	24504	22870	23440	26216	26412	25405	**25466**
L/R Balance	**2559**	**3047**	**5297**	**4118**	**532**	**877**	**1128**	**1012**	**2197**	**4046**	**3501**	**2612**	**2584**
W/O Plan Adjustment	1259	1747	3997	2818	-768	-423	-172	-288	897	2746	2201	1312	**1284**
W/O Uncontracted	259	747	652	-561	-4149	-3780	-3054	-2703	-1487	1746	1201	312	**-888**

Demand	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Ann
Non-DSI	19900	20300	22515	24475	25114	24074	22448	20793	20179	20965	21595	21317	**21966**
DSI	693	693	693	693	718	718	718	718	718	718	718	718	**710**
Coulee Pumping	137	65	2	2	2	2	28	158	238	255	274	238	**117**
Total	**20730**	**21058**	**23210**	**25171**	**25834**	**24795**	**23194**	**21670**	**21135**	**21938**	**22587**	**22273**	**22793**

Resources	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Ann
Critical Hydro	10579	11172	12724	13175	10482	10023	10740	10938	11487	15807	13300	12332	**11905**
Non-Hydro Firm	10720	10671	10862	11033	11099	10931	9582	8216	8270	8109	10812	10773	**10090**
PNW Uncontracted	1000	1000	3345	3379	3381	3357	2882	2415	2384	1000	1000	1000	**2171**
Planning Adjustment	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	**1300**

Firm Contracts	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Ann
Exports	1169	948	909	957	950	945	972	915	786	1022	1177	1216	**997**
Imports	859	910	1185	1359	1054	1006	790	727	678	790	853	696	**908**

PNW uncontracted resources are reduced during the peak SW load months June-October.

LEGEND:

NET DEMAND: Average annual firm load based on average temperature conditions and adjusted for firm out-of-region energy sales and purchases.
CRITICAL HYDRO: Hydro generation under current constraints for hydrologic conditions from August 1936 through July 1937.
NON-HYDRO FIRM: Annual energy capability from all non-hydro resources committed to serve PNW load accounting for maintenance and forced-outage rates & limited by fuel-supply constraints/environmental constraints (wind assumed at 30% plant factor unless better information available)
PNW UNCONTRACTED: Merchant generation located in the PNW, but not committed to load through long-term contracts.
PLANNING ADJUSTMENT: Additional energy available to PNW from out-of-region spot market and hydro flexibility derived from 5% LOLP study.

Energy Load/Resource Balance Assessment **2011**
NWPCC
May 28, 2008

Resource Detail	(MWa) **Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Ann**
18th Street (Springfield ICs,	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8
Alden Bailey (Loki)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Amalgamated Sugar (TASC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Amalgamated Sugar (TASC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Barber Dam	1.2	1.6	1.4	1.8	2.1	1.6	1.9	2.0	2.6	2.4	2.4	2.2	2
Basin Creek 1 - 9	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	8
Beaver 1 - 7	444.4	455.3	465.5	471.6	472.2	467.9	406.7	346.3	340.4	335.4	438.6	437.9	423
Beaver 8	21.0	21.5	22.0	22.3	22.3	22.1	19.2	16.4	16.1	15.9	20.7	20.7	20
Bennett Mountain	152.7	157.8	162.3	165.3	165.5	163.3	140.7	119.1	116.4	114.2	148.4	148.9	146
Big Sheep Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Biglow Canyon Ph I	35.4	27.5	32.0	36.1	38.7	33.9	40.3	40.3	45.5	40.3	41.8	40.3	38
Biomass One 1 & 2	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21
Birch Creek	2.7	0.0	0.0	0.0	0.0	0.0	0.0	2.7	2.7	2.7	2.7	2.7	1
Blind Canyon	0.4	0.5	0.5	0.6	0.7	0.5	0.6	0.7	0.9	0.8	0.8	0.7	1
Boardman	306.0	306.0	306.0	306.0	306.0	306.0	257.2	208.3	208.3	208.3	306.0	306.0	278
Boulder Park 1-6	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21
Boundary GT	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	1
Box Canyon	0.2	0.2	0.2	0.3	0.3	0.2	0.3	0.3	0.4	0.4	0.4	0.3	0
Box Canyon 1 & 2	1.0	1.3	1.1	1.5	1.7	1.3	1.5	1.6	2.1	2.0	2.0	1.8	2
Briggs Creek	0.2	0.3	0.3	0.4	0.4	0.3	0.4	0.4	0.5	0.5	0.5	0.4	0
Broadwater	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.9	1.0	1.4	1.0	0.7	1
Bypass	10.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	10.0	10.0	10.0	10.0	5
Cedar Draw Creek	1.0	1.3	1.1	1.4	1.6	1.3	1.5	1.6	2.1	1.9	1.9	1.7	2
Central Oregon Siphon	1.8	2.4	2.1	2.7	3.1	2.4	2.8	3.0	3.9	3.6	3.6	3.3	3
Centralia 1	93.0	93.0	93.0	93.0	93.0	93.0	78.1	63.3	63.3	63.3	93.0	93.0	84
Chehalis Generating Facilit	464.9	476.4	487.0	493.4	494.0	489.6	425.6	362.3	356.2	350.9	458.9	458.1	443
Clearwater Hatchery (Dwors	0.3	0.4	0.4	0.5	0.6	0.4	0.5	0.5	0.7	0.7	0.7	0.6	1
Coffin Butte 1 - 5	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	5
Cogen II (D.R. Johnson) 1 8	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	7
Colstrip 1	139.9	139.9	139.9	139.9	139.9	139.9	117.6	95.2	95.2	95.2	139.9	139.9	127
Colstrip 2	139.9	139.9	139.9	139.9	139.9	139.9	117.6	95.2	95.2	95.2	139.9	139.9	127
Colstrip 3	462.7	462.7	462.7	462.7	462.7	462.7	388.9	315.0	315.0	315.0	462.7	462.7	420
Colstrip 4	387.1	387.1	387.1	387.1	387.1	387.1	325.3	263.5	263.5	263.5	387.1	387.1	351
Columbia Generating Statio	1046.5	1046.5	1046.5	1046.5	1046.5	1046.5	845.0	643.5	643.5	643.5	1046.5	1046.5	929

Combine Hills I	11.6	9.0	10.5	11.8	12.7	11.1	13.2	13.2	14.9	13.2	13.7	13.2	12
Condon	14.0	10.9	12.7	14.3	15.4	13.4	16.0	16.0	18.1	16.0	16.6	16.0	15
COPCO 1 (1 & 2)	7.8	10.3	9.2	11.6	13.4	10.3	12.0	13.0	17.1	15.9	15.9	14.3	13
COPCO 2 (1 & 2)	10.5	13.7	12.2	15.5	17.8	13.8	16.0	17.3	22.7	21.1	21.2	19.1	17
Corrette (J.E. Corette)	22.9	22.9	22.9	22.9	22.9	22.9	19.3	15.6	15.6	15.6	22.9	22.9	21
Covanta Marion	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8
Cowiche Hydroelectric Proje	2.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.0	2.0	2.0	2.0	1
Coyote Springs 1	216.4	223.7	230.1	234.4	234.7	231.4	199.4	168.9	165.0	161.8	210.4	211.0	207
Coyote Springs 2	231.3	239.0	245.9	250.5	250.8	247.4	213.2	180.5	176.4	173.0	224.8	225.5	221
Crystal Mountain	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	3
Danskin (Evander Andrews)	145.8	150.7	155.0	157.9	158.1	155.9	134.4	113.8	111.2	109.0	141.7	142.2	140
Danskin (Evander Andrews)	39.5	40.8	41.9	42.7	42.8	42.2	36.4	30.8	30.1	29.5	38.4	38.5	38
Danskin (Evander Andrews)	39.5	40.8	41.9	42.7	42.8	42.2	36.4	30.8	30.1	29.5	38.4	38.5	38
Deep Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Dietrich Drop	4.8	0.0	0.0	0.0	0.0	0.0	0.0	4.8	4.8	4.8	4.8	4.8	2
Don Plant (Simplot Pocatelli	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	6
Dry Creek	3.6	0.0	0.0	0.0	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	2
Dry Creek Landfill	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	3
Eastsound 4 & 5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Elk Creek	0.8	1.0	0.9	1.1	1.3	1.0	1.2	1.3	1.6	1.5	1.5	1.4	1
Elkhorn	28.2	21.9	25.5	28.8	30.9	27.0	32.1	32.1	36.3	32.1	33.3	32.1	30
Eltopia Branch Canal 4.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Encogen 1-4	143.1	146.6	149.9	151.8	152.0	150.6	130.9	111.5	109.6	108.0	141.2	141.0	136
Everett Cogeneration Projec	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30
Evergreen Forest Products	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4
Fall Creek 1 - 3	0.7	0.9	0.8	1.0	1.1	0.9	1.0	1.1	1.4	1.3	1.3	1.2	1
Fall River	3.0	3.9	3.5	4.4	5.1	3.9	4.6	4.9	6.5	6.0	6.0	5.4	5
Falls Creek	1.3	1.7	1.5	1.9	2.2	1.7	2.0	2.2	2.8	2.6	2.6	2.4	2
Farmers Irr. Dist. No. 2 (Co	1.0	1.3	1.1	1.5	1.7	1.3	1.5	1.6	2.1	2.0	2.0	1.8	2
Farmers Irr. Dist. No. 3 (Pet	1.8	0.0	0.0	0.0	0.0	0.0	0.0	1.8	1.8	1.8	1.8	1.8	1
Faulkner	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.9	0.9	0.9	0.9	0
Foote Creek 1	11.7	9.1	10.6	11.9	12.8	11.2	13.3	13.3	15.0	13.3	13.8	13.3	12
Foote Creek 2	0.5	0.4	0.5	0.5	0.6	0.5	0.6	0.6	0.7	0.6	0.6	0.6	1
Foote Creek 4	4.7	3.7	4.3	4.8	5.2	4.5	5.4	5.4	6.1	5.4	5.6	5.4	5
Fortix	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Fossil Gulch	3.0	2.3	2.7	3.0	3.2	2.8	3.4	3.4	3.8	3.4	3.5	3.4	3
Frederickson 1	77.9	79.8	81.6	82.7	82.8	82.0	71.3	60.7	59.7	58.8	76.9	76.8	74
Frederickson 2	77.9	79.8	81.6	82.7	82.8	82.0	71.3	60.7	59.7	58.8	76.9	76.8	74
Frederickson Power 1	240.5	246.4	251.9	255.2	255.6	253.3	220.1	187.4	184.3	181.5	237.4	237.0	229
Fredonia 1	108.5	111.2	113.7	115.2	115.3	114.3	99.3	84.6	83.2	81.9	107.1	106.9	103

Fredonia 2	108.5	111.2	113.7	115.2	115.3	114.3	99.3	84.6	83.2	81.9	107.1	106.9	103
Fredonia 3	51.7	52.9	54.1	54.8	54.9	54.4	49.6	44.8	44.0	43.4	51.0	50.9	51
Fredonia 4	50.8	52.1	53.2	53.9	54.0	53.5	48.8	44.0	43.3	42.6	50.2	50.1	50
Freres Lumber	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8
Galesville	0.5	0.6	0.8	0.9	0.9	0.7	0.7	0.7	0.8	0.8	0.7	0.8	1
Geo-Bon No. 2	0.3	0.5	0.4	0.5	0.6	0.5	0.5	0.6	0.8	0.7	0.7	0.6	1
Georgia-Pacific (Camas)	43.7	43.7	43.7	43.7	43.7	43.7	43.7	43.7	43.7	43.7	43.7	43.7	44
Georgia-Pacific (Wauna)	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	23
Glenns Ferry Cogeneration	8.8	9.1	9.3	9.5	9.5	9.4	8.1	6.8	6.7	6.6	8.5	8.5	8
Goldendale CC 1A & 1B	217.3	224.6	231.0	235.3	235.6	232.4	200.2	169.6	165.7	162.5	211.2	211.9	208
Goodnoe Hills	26.5	20.6	24.0	27.1	29.0	25.4	30.2	30.2	34.1	30.2	31.3	30.2	28
Grant Village 1 & 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
H.W. Hill (Roosevelt Biogas	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9
Hampton Lumber	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6
Hazelton A	8.7	0.0	0.0	0.0	0.0	0.0	0.0	8.7	8.7	8.7	8.7	8.7	4
Hazelton B	7.6	0.0	0.0	0.0	0.0	0.0	0.0	7.6	7.6	7.6	7.6	7.6	4
Hermiston Generating Proje	206.8	213.7	219.8	223.9	224.2	221.1	190.6	161.4	157.7	154.6	201.0	201.6	198
Hermiston Generating Proje	206.8	213.7	219.8	223.9	224.2	221.1	190.6	161.4	157.7	154.6	201.0	201.6	198
Hidden Hollow	3.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	3.0	3.0	3.0	3.0	2
Hopkins Ridge	42.1	32.7	38.1	43.0	46.2	40.3	48.0	48.0	54.2	48.0	49.8	48.0	45
Hoquiam Diesels	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	9
Horseshoe Bend	2.5	2.0	2.3	2.6	2.8	2.4	2.9	2.9	3.3	2.9	3.0	2.9	3
Horseshoe Bend Hydroelec	3.1	4.1	3.6	4.6	5.3	4.1	4.8	5.1	6.8	6.3	6.3	5.7	5
Ingram Warm Springs Ranc	0.2	0.2	0.2	0.2	0.3	0.2	0.3	0.3	0.4	0.3	0.3	0.3	0
Ingram Warm Springs Ranc	0.4	0.5	0.4	0.5	0.6	0.5	0.5	0.6	0.8	0.7	0.7	0.6	1
Iron Gate	5.9	7.7	6.9	8.7	10.0	7.7	9.0	9.7	12.8	11.9	11.9	10.8	9
Jim Bridger 1	492.9	492.9	492.9	492.9	492.9	492.9	414.2	335.5	335.5	335.5	492.9	492.9	447
Jim Bridger 2	492.9	492.9	492.9	492.9	492.9	492.9	414.2	335.5	335.5	335.5	492.9	492.9	447
Jim Bridger 3	492.9	492.9	492.9	492.9	492.9	492.9	414.2	335.5	335.5	335.5	492.9	492.9	447
Jim Bridger 4	492.9	492.9	492.9	492.9	492.9	492.9	414.2	335.5	335.5	335.5	492.9	492.9	447
Jim Ford Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
John Day Creek (Cereghinc	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
John H. Koyle	0.5	0.6	0.5	0.7	0.8	0.6	0.7	0.8	1.0	0.9	0.9	0.8	1
Judith Gap	6.1	4.7	5.5	6.2	6.7	5.8	6.9	6.9	7.8	6.9	7.2	6.9	6
Kasel-Witherspoon	0.5	0.6	0.5	0.7	0.8	0.6	0.7	0.8	1.0	0.9	0.9	0.8	1
Kettle Falls Generating Stat	44.6	44.6	44.6	44.6	44.6	44.6	44.6	44.6	44.6	44.6	44.6	44.6	45
Kettle Falls GT	6.0	6.2	6.4	6.5	6.5	6.4	5.5	4.7	4.6	4.5	5.8	5.9	6
Klondike I	6.8	5.3	6.1	6.9	7.4	6.5	7.7	7.7	8.7	7.7	8.0	7.7	7
Klondike II	21.2	16.4	19.1	21.6	23.2	20.3	24.1	24.1	27.2	24.1	25.0	24.1	23
Klondike III	20.2	15.7	18.3	20.7	22.2	19.4	23.0	23.0	26.1	23.0	23.9	23.0	22

Koma Kulshan	3.9	4.4	6.0	6.5	6.3	4.7	5.0	5.1	5.6	5.6	5.3	5.5	5
Lacomb	1.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0	1.0	0
Lake	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Lancaster (Rathdrum CC)	243.6	251.7	258.9	263.8	264.1	260.5	224.5	190.1	185.8	182.2	236.8	237.5	233
Lateral No. 10	2.9	0.0	0.0	0.0	0.0	0.0	0.0	2.9	2.9	2.9	2.9	2.9	1
Leaning Juniper	28.3	22.0	25.6	28.9	31.1	27.1	32.3	32.3	36.5	32.3	33.5	32.3	30
Little Wood Reservoir	0.3	0.4	0.4	0.5	0.6	0.4	0.5	0.6	0.7	0.7	0.7	0.6	1
Little Wood River Ranch	0.6	0.8	0.7	0.9	1.1	0.8	1.0	1.0	1.4	1.3	1.3	1.2	1
Lower Low Line No. 2	2.8	0.0	0.0	0.0	0.0	0.0	0.0	2.8	2.8	2.8	2.8	2.8	1
LQ-LS Drains	0.6	0.8	0.7	0.8	1.0	0.8	0.9	0.9	1.2	1.2	1.2	1.0	1
Lucky Peak 1 - 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
MacClaren	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Magic Dam	2.9	3.9	3.4	4.4	5.0	3.9	4.5	4.9	6.4	5.9	6.0	5.4	5
Main Canal Headworks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
March Point 1 - 4	125.2	128.2	131.1	132.8	133.0	131.8	114.6	97.5	95.9	94.5	123.5	123.3	119
Marengo I	39.6	30.7	35.8	40.4	43.4	37.9	45.1	45.1	51.0	45.1	46.8	45.1	42
Marengo II	19.8	15.4	17.9	20.2	21.7	19.0	22.5	22.5	25.5	22.5	23.4	22.5	21
Meyers Falls	0.3	0.4	0.4	0.5	0.6	0.4	0.5	0.5	0.7	0.7	0.7	0.6	1
Middle Fork Irrigation Distric	0.2	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0
Middle Fork Irrigation Distric	0.2	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0
Middle Fork Irrigation Distric	0.7	0.9	0.8	1.0	1.2	0.9	1.1	1.1	1.5	1.4	1.4	1.3	1
Mile 28	1.8	0.0	0.0	0.0	0.0	0.0	0.0	1.8	1.8	1.8	1.8	1.8	1
Mink Creek	1.0	1.3	1.2	1.5	1.7	1.3	1.6	1.7	2.2	2.0	2.1	1.9	2
Mirror Lake (Hutchinson Cre	1.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0	1.0	1
Mitchell Butte	1.9	0.0	0.0	0.0	0.0	0.0	0.0	1.9	1.9	1.9	1.9	1.9	1
Montana One (Colstrip Ene	4.7	4.7	4.7	4.7	4.7	4.7	3.9	3.2	3.2	3.2	4.7	4.7	4
N-32 (Northside Canal)	0.2	0.2	0.2	0.3	0.3	0.2	0.3	0.3	0.4	0.4	0.4	0.3	0
Nichols Gap	0.3	0.3	0.4	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0
Nine Canyon	18.0	14.0	16.2	18.3	19.7	17.2	20.4	20.4	23.1	20.4	21.2	20.4	19
North Fork Sprague River	0.4	0.5	0.5	0.6	0.7	0.5	0.6	0.7	0.9	0.8	0.8	0.7	1
North Valmy 1	59.1	59.1	59.1	59.1	59.1	59.1	49.6	40.2	40.2	40.2	59.1	59.1	54
North Valmy 2	60.0	60.0	60.0	60.0	60.0	60.0	50.4	40.8	40.8	40.8	60.0	60.0	54
Northeast 1	5.4	5.6	5.7	5.8	5.8	5.7	5.2	4.7	4.6	4.6	5.4	5.3	5
Northeast 2	5.4	5.6	5.7	5.8	5.8	5.7	5.2	4.7	4.6	4.6	5.4	5.3	5
Old Faithful 1 & 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Olympic View 1 & 2	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	5
Opal Springs	1.4	1.8	1.6	2.1	2.4	1.9	2.2	2.3	3.1	2.8	2.8	2.6	2
Owyhee Dam	1.4	1.9	1.7	2.1	2.4	1.9	2.2	2.3	3.1	2.9	2.9	2.6	2
Owyhee Tunnel No. 1	8.0	0.0	0.0	0.0	0.0	0.0	0.0	8.0	8.0	8.0	8.0	8.0	4
Pasco (Franklin/Grays) GT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0

Pasco (Franklin/Grays) GT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Pasco (Franklin/Grays) GT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Pasco (Franklin/Grays) GT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Plummer Forest Products	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5
Point Whitehorn 2	77.9	79.8	81.6	82.7	82.8	82.0	71.3	60.7	59.7	58.8	76.9	76.8	74
Point Whitehorn 3	77.9	79.8	81.6	82.7	82.8	82.0	71.3	60.7	59.7	58.8	76.9	76.8	74
Port Westward CC1A & 1B	380.9	390.2	399.0	404.2	404.7	401.1	348.6	296.8	291.8	287.4	375.9	375.3	363
Portneuf River	0.3	0.4	0.3	0.4	0.5	0.4	0.5	0.5	0.6	0.6	0.6	0.5	0
Potholes East Canal 66.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Potholes East Canal Headw	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Potlatch (Lewiston) 1 - 4	49.6	49.6	49.6	49.6	49.6	49.6	49.6	49.6	49.6	49.6	49.6	49.6	50
Prather Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Raft River I	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12
Rathdrum 1	75.5	78.0	80.2	81.7	81.8	80.7	69.6	58.9	57.6	56.4	73.4	73.6	72
Rathdrum 2	75.5	78.0	80.2	81.7	81.8	80.7	69.6	58.9	57.6	56.4	73.4	73.6	72
River Road Generating Plar	221.7	227.2	232.3	235.3	235.6	233.5	203.0	172.8	169.9	167.3	218.9	218.5	211
Rock Creek #1	0.8	1.1	1.0	1.2	1.4	1.1	1.3	1.4	1.8	1.7	1.7	1.5	1
Rock Creek #2	0.6	0.8	0.7	0.9	1.1	0.8	1.0	1.0	1.4	1.3	1.3	1.1	1
Rock River I	14.1	11.0	12.8	14.4	15.5	13.5	16.1	16.1	18.2	16.1	16.7	16.1	15
Ross Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0
Rough & Ready Lumber	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1
Rupert Cogeneration	8.8	9.1	9.3	9.5	9.5	9.4	8.1	6.8	6.7	6.6	8.5	8.5	8
Russell D. Smith	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Salmon 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Salmon 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Savage Rapids Diversion	0.4	0.5	0.6	0.7	0.7	0.5	0.5	0.5	0.6	0.6	0.6	0.6	1
Shasta River	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Short Mountain 1 - 4	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2
Shoshone/Shoshone II	0.3	0.4	0.3	0.4	0.5	0.4	0.5	0.5	0.6	0.6	0.6	0.5	0
Sierra Pacific (Aberdeen)	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5
Sierra Pacific (Fredonia)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0
Skookumchuck	0.3	0.4	0.5	0.5	0.5	0.4	0.4	0.4	0.5	0.5	0.4	0.5	0
Slate Creek	1.4	1.8	1.6	2.0	2.3	1.8	2.1	2.3	3.0	2.8	2.8	2.5	2
South Dry Creek	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0
St. Anthony	0.2	0.2	0.2	0.2	0.3	0.2	0.3	0.3	0.4	0.3	0.3	0.3	0
Stateline	84.6	65.7	76.5	86.4	92.7	81.0	96.3	96.3	108.9	96.3	99.9	96.3	90
Sumas Energy	110.0	112.7	115.2	116.7	116.9	115.8	100.7	85.7	84.3	83.0	108.5	108.4	105
Summer Falls 1 & 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Tenaska Washington Partn	219.0	224.4	229.5	232.5	232.8	230.7	200.5	170.7	167.8	165.3	216.2	215.8	209
Tiber-Montana	1.6	2.1	1.9	2.4	2.8	2.2	2.5	2.7	3.6	3.3	3.3	3.0	3

Tieton	4.4	5.8	5.2	6.6	7.6	5.9	6.8	7.4	9.7	9.0	9.0	8.1	7
Tuttle Ranch (Ravenscroft)	0.3	0.5	0.4	0.5	0.6	0.5	0.5	0.6	0.8	0.7	0.7	0.6	1
Twin Falls (TFHA)	6.5	8.6	7.6	9.7	11.2	8.6	10.0	10.8	14.2	13.2	13.2	12.0	10
Twin Reservoirs	1.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0	1.0	1
U.S. Bankcorp IC1 - IC4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Upriver	4.6	6.0	5.3	6.8	7.8	6.0	7.0	7.6	9.9	9.2	9.3	8.4	7
Vaagen Brothers Lumber	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	3
Vansycle Wind Energy Proj	7.0	5.5	6.3	7.2	7.7	6.7	8.0	8.0	9.0	8.0	8.3	8.0	7
Wapato Drop 2 (#1)	3.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	3.0	3.0	3.0	3.0	2
Wapato Drop 3 (#1 - 2)	2.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.0	2.0	2.0	2.0	1
Weeks Falls	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Weyerhaeuser (Springfield)	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21
Wheelabrator Spokane	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19
White Creek	56.0	43.5	50.6	57.2	61.4	53.6	63.8	63.8	72.1	63.8	66.1	63.8	60
Wild Horse Wind	64.5	50.1	58.3	65.8	70.6	61.7	73.4	73.4	83.0	73.4	76.1	73.4	69
Wilson Lake	8.4	0.0	0.0	0.0	0.0	0.0	0.0	8.4	8.4	8.4	8.4	8.4	4
Wolverine Creek	18.2	14.1	16.4	18.6	19.9	17.4	20.7	20.7	23.4	20.7	21.5	20.7	19
WSU Grimes Way Central S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Yellowstone Energy (BGI)	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6
Total	**10720**	**10671**	**10862**	**11033**	**11099**	**10931**	**9582**	**8216**	**8270**	**8109**	**10812**	**10773**	**10090**
Uncommitted IPPs													
Big Hanaford CC1A-1E	221.7	227.2	232.3	235.3	235.6	233.5	203.0	172.8	169.9	167.3	218.9	218.5	211
Centralia 1	530.1	530.1	530.1	530.1	530.1	530.1	445.4	360.8	360.8	360.8	530.1	530.1	481
Centralia 2	623.1	623.1	623.1	623.1	623.1	623.1	523.6	424.1	424.1	424.1	623.1	623.1	565
Grays Harbor Energy Facilit	581.1	595.4	608.8	616.8	617.5	612.0	532.0	452.9	445.3	438.6	573.6	572.7	554
Hermiston Power Project	464.4	479.9	493.7	502.9	503.5	496.6	428.0	362.4	354.2	347.3	451.4	452.8	445
Klamath Cogeneration Proje	420.6	434.6	447.1	455.5	456.0	449.7	387.6	328.2	320.7	314.5	408.8	410.1	403
Klamath Generation Peaker	42.4	43.4	44.4	44.9	45.0	44.6	40.6	36.7	36.1	35.5	41.8	41.7	41
Klamath Generation Peaker	42.4	43.4	44.4	44.9	45.0	44.6	40.6	36.7	36.1	35.5	41.8	41.7	41
Mint Farm	285.2	292.2	298.8	302.7	303.1	300.3	261.1	222.3	218.5	215.2	281.5	281.0	272
Morrow Power	21.2	21.7	22.2	22.5	22.5	22.3	20.3	18.3	18.0	17.8	20.9	20.9	21
West Point Treatment Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Total	**3232**	**3291**	**3345**	**3379**	**3381**	**3357**	**2882**	**2415**	**2384**	**2357**	**3192**	**3193**	**3033**

Pacific Northwest Regional Resource Adequacy Assessment

Capacity Reserve Margin Assessment | **2011** | **Jan RM** | **46%** | **Jan Threshold** | **23%**
NWPCC | | **Jul RM** | **34%** | **Jul Threshold** | **24%**
May 28, 2008 **Last Update**

Summary	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
Peak Demand	24100	24429	26243	28571	28603	27796	26496	24690	23912	25043	26313	25920
Peak Resources	32424	33175	40463	41348	41842	39911	37140	35659	37917	34106	35297	33053
Reserve Margin	**35%**	**36%**	**54%**	**45%**	**46%**	**44%**	**40%**	**44%**	**59%**	**36%**	**34%**	**28%**
W/O Uncontracted	30%	32%	29%	22%	23%	20%	17%	22%	35%	32%	30%	24%

Sust Peak Demand	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
Non-DSI	22000	22825	25235	27735	27501	26701	24915	22879	22050	22786	24032	23531
DSI	693	693	693	693	718	718	718	718	718	718	718	718
Coulee Pumping	137	65	2	2	2	2	28	158	238	255	274	238
Total	**22831**	**23584**	**25930**	**28430**	**28222**	**27421**	**25661**	**23756**	**23006**	**23759**	**25024**	**24488**

Sust Peak Resources	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
Hydro	18855	19476	20071	20810	21278	19465	18857	19522	21853	23661	21760	19528
Hydro Flex	1000	1000	2000	2000	2000	2000	2000	2000	2000	1000	1000	1000
PNW Uncontracted	1000	1000	3553	3589	3592	3566	3062	2565	2532	1000	1000	1000
Out-of-PNW Uncontracted	0	0	3000	3000	3000	3000	3000	3000	3000	0	0	0
Non-Hydro	11569	11699	11839	11949	11972	11879	10221	8571	8531	8445	11537	11525

On-Peak Contracts	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
Exports	2328	1946	1827	1833	1827	1823	1850	1834	1809	2348	2349	2336
Imports	1059	1101	1514	1692	1446	1448	1015	900	903	1064	1060	903

Hydro flex, PNW uncontracted and out-of-PNW uncontracted resources are reduced during the SW peak months June-October.

LEGEND:

PEAK DEMAND: Average load under normal temperatures over the peak load hours (6 hours/day over 3 weekdays).
HYDRO: Hydro capacity for sustained peaking period based on 6-hour Trap output for lowest quintile.
HYDRO FLEX: Additional hydro capacity over the sustained peaking period.
PNW UNCONTRACTED: Merchant capacity located and availble to the PNW, but not committed to load through long-term contracts.
OUT-OF-PNW UNCONTRACTED: Out-of-region resources available to PNW based on an analysis of California winter surplus capacity.
NON-HYDRO: Capacity available over sustained peaking period from all non-hydro resources accounting for
maintenance outages & limited by fuel-supply constraints/environmental constraints (wind assumed at 5% plant factor for now).

Capacity Reserve Margin Assessment **2011**
NWPCC
May 28, 2008

Resource Detail (MW)	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**
18th Street (Springfield ICs,	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Alden Bailey (Loki)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Amalgamated Sugar (TASC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Amalgamated Sugar (TASC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Barber Dam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Basin Creek 1 - 9	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
Beaver 1 - 7	467.7	479.2	490.0	496.4	497.0	492.6	428.1	364.5	358.4	353.0	461.7	460.9
Beaver 8	22.6	23.1	23.7	24.0	24.0	23.8	20.7	17.6	17.3	17.0	22.3	22.3
Bennett Mountain	164.2	169.7	174.5	177.8	178.0	175.6	151.3	128.1	125.2	122.8	159.6	160.1
Big Sheep Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biglow Canyon Ph I	5.3	4.1	4.8	5.4	5.8	5.1	6.0	6.0	6.8	6.0	6.3	6.0
Biomass One 1 & 2	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6
Birch Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Blind Canyon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Boardman	438.8	438.8	438.8	438.8	438.8	438.8	368.7	298.6	298.6	298.6	438.8	438.8
Boulder Park 1-6	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1
Boundary GT	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Box Canyon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Box Canyon 1 & 2	1.0	1.3	1.1	1.5	1.7	1.3	1.5	1.6	2.1	2.0	2.0	1.8
Briggs Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Broadwater	1.7	1.8	1.9	2.0	2.0	2.0	2.0	2.2	2.5	3.4	2.5	1.8
Bypass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cedar Draw Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Central Oregon Siphon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Centralia 1	100.0	100.0	100.0	100.0	100.0	100.0	84.0	68.1	68.1	68.1	100.0	100.0
Chehalis Generating Facilit	489.4	501.4	512.7	519.4	520.0	515.4	448.0	381.4	374.9	369.3	483.0	482.2
Clearwater Hatchery (Dwor	0.3	0.4	0.4	0.5	0.6	0.4	0.5	0.5	0.7	0.7	0.7	0.6
Coffin Butte 1 - 5	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Cogen II (D.R. Johnson) 1 &	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Colstrip 1	214.9	214.9	214.9	214.9	214.9	214.9	180.6	146.3	146.3	146.3	214.9	214.9
Colstrip 2	214.9	214.9	214.9	214.9	214.9	214.9	180.6	146.3	146.3	146.3	214.9	214.9

Colstrip 3	606.8	606.8	606.8	606.8	606.8	606.8	509.9	413.0	413.0	413.0	606.8	606.8
Colstrip 4	555.0	555.0	555.0	555.0	555.0	555.0	466.4	377.7	377.7	377.7	555.0	555.0
Columbia Generating Statio	1150.0	1150.0	1150.0	1150.0	1150.0	1150.0	928.6	707.1	707.1	707.1	1150.0	1150.0
Combine Hills I	1.7	1.3	1.6	1.8	1.9	1.7	2.0	2.0	2.2	2.0	2.0	2.0
Condon	2.1	1.6	1.9	2.2	2.3	2.0	2.4	2.4	2.7	2.4	2.5	2.4
COPCO 1 (1 & 2)	7.8	10.3	9.2	11.6	13.4	10.3	12.0	13.0	17.1	15.9	15.9	14.3
COPCO 2 (1 & 2)	10.5	13.7	12.2	15.5	17.8	13.8	16.0	17.3	22.7	21.1	21.2	19.1
Corrette (J.E. Corette)	61.6	61.6	61.6	61.6	61.6	61.6	51.8	41.9	41.9	41.9	61.6	61.6
Covanta Marion	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Cowiche Hydroelectric Proje	2.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.0	2.0	2.0	2.0
Coyote Springs 1	227.8	235.4	242.2	246.7	247.0	243.6	209.9	177.8	173.7	170.4	221.4	222.1
Coyote Springs 2	243.5	251.6	258.8	263.7	264.0	260.4	224.4	190.0	185.7	182.1	236.7	237.4
Crystal Mountain	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Danskin (Evander Andrews	156.8	162.0	166.7	169.8	170.0	167.7	144.5	122.4	119.6	117.3	152.4	152.9
Danskin (Evander Andrews	42.4	43.8	45.1	45.9	46.0	45.4	39.1	33.1	32.4	31.7	41.2	41.4
Danskin (Evander Andrews	42.4	43.8	45.1	45.9	46.0	45.4	39.1	33.1	32.4	31.7	41.2	41.4
Deep Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dietrich Drop	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Don Plant (Simplot Pocatell	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
Dry Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dry Creek Landfill	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Eastsound 4 & 5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Elk Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Elkhorn	4.2	3.3	3.8	4.3	4.6	4.1	4.8	4.8	5.4	4.8	5.0	4.8
Eltopia Branch Canal 4.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Encogen 1-4	150.6	154.3	157.7	159.8	160.0	158.6	137.8	117.3	115.4	113.6	148.6	148.4
Everett Cogeneration Projec	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5
Evergreen Forest Products	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Fall Creek 1 - 3	0.7	0.9	0.8	1.0	1.1	0.9	1.0	1.1	1.4	1.3	1.3	1.2
Fall River	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Falls Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Farmers Irr. Dist. No. 2 (Co	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Farmers Irr. Dist. No. 3 (Pet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Faulkner	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Foote Creek 1	1.8	1.4	1.6	1.8	1.9	1.7	2.0	2.0	2.3	2.0	2.1	2.0
Foote Creek 2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Foote Creek 4	0.7	0.6	0.6	0.7	0.8	0.7	0.8	0.8	0.9	0.8	0.8	0.8

Fortix	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Fossil Gulch	0.4	0.3	0.4	0.5	0.5	0.4	0.5	0.5	0.6	0.5	0.5	0.5
Frederickson 1	83.8	85.8	87.7	88.9	89.0	88.2	76.7	65.3	64.2	63.2	82.7	82.5
Frederickson 2	83.8	85.8	87.7	88.9	89.0	88.2	76.7	65.3	64.2	63.2	82.7	82.5
Frederickson Power 1	253.2	259.4	265.2	268.7	269.0	266.6	231.7	197.3	194.0	191.1	249.9	249.5
Fredonia 1	116.7	119.6	122.2	123.9	124.0	122.9	106.8	90.9	89.4	88.1	115.2	115.0
Fredonia 2	116.7	119.6	122.2	123.9	124.0	122.9	106.8	90.9	89.4	88.1	115.2	115.0
Fredonia 3	57.4	58.8	60.1	60.9	61.0	60.5	55.1	49.7	48.9	48.2	56.7	56.6
Fredonia 4	56.5	57.9	59.2	59.9	60.0	59.5	54.2	48.9	48.1	47.4	55.7	55.6
Freres Lumber	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Galesville	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geo-Bon No. 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Georgia-Pacific (Camas)	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0
Georgia-Pacific (Wauna)	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Glenns Ferry Cogeneration	9.2	9.5	9.8	10.0	10.0	9.9	8.5	7.2	7.0	6.9	9.0	9.0
Goldendale CC 1A & 1B	228.7	236.4	243.2	247.7	248.0	244.6	210.8	178.5	174.4	171.0	222.3	223.0
Goodnoe Hills	4.0	3.1	3.6	4.1	4.4	3.8	4.5	4.5	5.1	4.5	4.7	4.5
Grant Village 1 & 2	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
H.W. Hill (Roosevelt Biogas	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Hampton Lumber	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
Hazelton A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hazelton B	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hermiston Generating Proje	217.7	224.9	231.4	235.7	236.0	232.8	200.6	169.9	166.0	162.8	211.6	212.2
Hermiston Generating Proje	217.7	224.9	231.4	235.7	236.0	232.8	200.6	169.9	166.0	162.8	211.6	212.2
Hidden Hollow	3.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	3.0	3.0	3.0	3.0
Hopkins Ridge	6.3	4.9	5.7	6.5	6.9	6.1	7.2	7.2	8.1	7.2	7.5	7.2
Hoquiam Diesels	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
Horseshoe Bend	0.4	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.5	0.4	0.4	0.4
Horseshoe Bend Hydroelec	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ingram Warm Springs Ranc	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ingram Warm Springs Ranc	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Iron Gate	5.9	7.7	6.9	8.7	10.0	7.7	9.0	9.7	12.8	11.9	11.9	10.8
Jim Bridger 1	530.0	530.0	530.0	530.0	530.0	530.0	445.4	360.7	360.7	360.7	530.0	530.0
Jim Bridger 2	530.0	530.0	530.0	530.0	530.0	530.0	445.4	360.7	360.7	360.7	530.0	530.0
Jim Bridger 3	530.0	530.0	530.0	530.0	530.0	530.0	445.4	360.7	360.7	360.7	530.0	530.0
Jim Bridger 4	530.0	530.0	530.0	530.0	530.0	530.0	445.4	360.7	360.7	360.7	530.0	530.0
Jim Ford Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

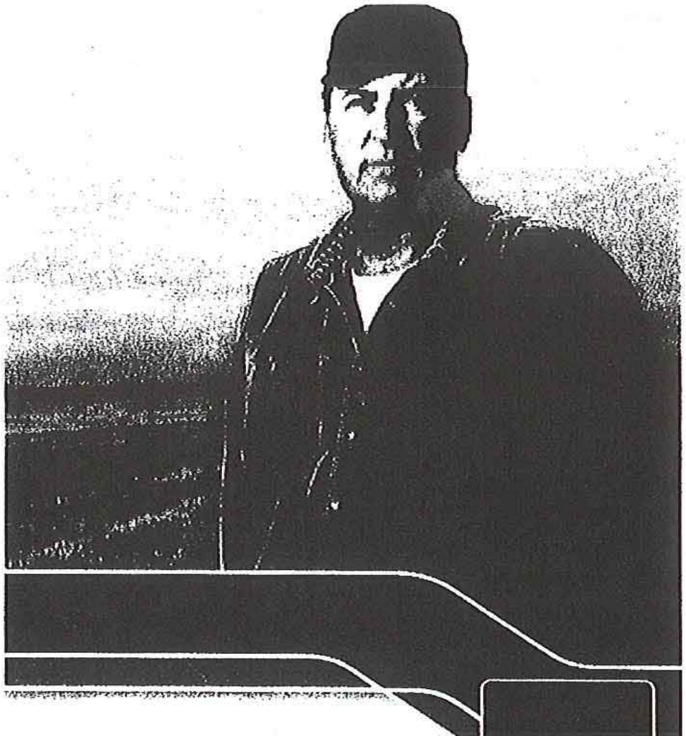
John Day Creek (Cereghinc	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
John H. Koyle	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Judith Gap	2.3	1.8	2.1	2.3	2.5	2.2	2.6	2.6	2.9	2.6	2.7	2.6
Kasel-Witherspoon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kettle Falls Generating Stat	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9	47.9
Kettle Falls GT	6.5	6.7	6.9	7.0	7.0	6.9	5.9	5.0	4.9	4.8	6.3	6.3
Klondike I	1.0	0.8	0.9	1.0	1.1	1.0	1.2	1.2	1.3	1.2	1.2	1.2
Klondike II	3.2	2.5	2.9	3.2	3.5	3.0	3.6	3.6	4.1	3.6	3.7	3.6
Klondike III	5.3	4.1	4.8	5.4	5.8	5.1	6.1	6.1	6.9	6.1	6.3	6.1
Koma Kulshan	3.9	4.4	6.0	6.5	6.3	4.7	5.0	5.1	5.6	5.6	5.3	5.5
Lacomb	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lake	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lancaster (Rathdrum CC)	256.4	265.0	272.6	277.7	278.0	274.2	236.3	200.1	195.5	191.7	249.2	250.0
Lateral No. 10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Leaning Juniper	4.3	3.3	3.8	4.3	4.7	4.1	4.8	4.8	5.5	4.8	5.0	4.8
Little Wood Reservoir	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Little Wood River Ranch	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lower Low Line No. 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LQ-LS Drains	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lucky Peak 1 - 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MacClaren	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Magic Dam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Main Canal Headworks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
March Point 1 - 4	131.8	135.0	138.0	139.8	140.0	138.7	120.6	102.7	100.9	99.4	130.1	129.8
Marengo I	5.9	4.6	5.4	6.1	6.5	5.7	6.8	6.8	7.6	6.8	7.0	6.8
Marengo II	3.0	2.3	2.7	3.0	3.3	2.8	3.4	3.4	3.8	3.4	3.5	3.4
Meyers Falls	0.3	0.4	0.4	0.5	0.6	0.4	0.5	0.5	0.7	0.7	0.7	0.6
Middle Fork Irrigation Distric	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Middle Fork Irrigation Distric	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Middle Fork Irrigation Distric	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mile 28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mink Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mirror Lake (Hutchinson Cre	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mitchell Butte	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Montana One (Colstrip Ener	14.0	14.0	14.0	14.0	14.0	14.0	11.8	9.6	9.6	9.6	14.0	14.0
N-32 (Northside Canal)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nichols Gap	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Nine Canyon	2.7	2.1	2.4	2.8	3.0	2.6	3.1	3.1	3.5	3.1	3.2	3.1
North Fork Sprague River	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
North Valmy 1	127.0	127.0	127.0	127.0	127.0	127.0	106.7	86.4	86.4	86.4	127.0	127.0
North Valmy 2	129.0	129.0	129.0	129.0	129.0	129.0	108.4	87.8	87.8	87.8	129.0	129.0
Northeast 1	31.1	31.8	32.5	33.0	33.0	32.7	29.8	26.9	26.5	26.1	30.7	30.6
Northeast 2	31.1	31.8	32.5	33.0	33.0	32.7	29.8	26.9	26.5	26.1	30.7	30.6
Old Faithful 1 & 2	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Olympic View 1 & 2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Opal Springs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Owyhee Dam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Owyhee Tunnel No. 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pasco (Franklin/Grays) GT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pasco (Franklin/Grays) GT :	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pasco (Franklin/Grays) GT .	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pasco (Franklin/Grays) GT ·	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Plummer Forest Products	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Point Whitehorn 2	83.8	85.8	87.7	88.9	89.0	88.2	76.7	65.3	64.2	63.2	82.7	82.5
Point Whitehorn 3	83.8	85.8	87.7	88.9	89.0	88.2	76.7	65.3	64.2	63.2	82.7	82.5
Port Westward CC1A & 1B	400.9	410.8	420.0	425.5	426.0	422.2	367.0	312.4	307.2	302.6	395.7	395.1
Portneuf River	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Potholes East Canal 66.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Potholes East Canal Headw	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Potlatch (Lewiston) 1 - 4	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3
Prather Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Raft River I	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Rathdrum 1	81.2	83.9	86.3	87.9	88.0	86.8	74.8	63.3	61.9	60.7	78.9	79.1
Rathdrum 2	81.2	83.9	86.3	87.9	88.0	86.8	74.8	63.3	61.9	60.7	78.9	79.1
River Road Generating Plar	233.4	239.1	244.5	247.7	248.0	245.8	213.6	181.9	178.8	176.1	230.4	230.0
Rock Creek #1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rock Creek #2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rock River I	2.1	1.6	1.9	2.2	2.3	2.0	2.4	2.4	2.7	2.4	2.5	2.4
Ross Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rough & Ready Lumber	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Rupert Cogeneration	9.2	9.5	9.8	10.0	10.0	9.9	8.5	7.2	7.0	6.9	9.0	9.0
Russell D. Smith	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salmon 1	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Salmon 2	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9

Savage Rapids Diversion	0.4	0.5	0.6	0.7	0.7	0.5	0.5	0.5	0.6	0.6	0.6	0.6
Shasta River	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Short Mountain 1 - 4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Shoshone/Shoshone II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra Pacific (Aberdeen)	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Sierra Pacific (Fredonia)	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Skookumchuck	0.3	0.4	0.5	0.5	0.5	0.4	0.4	0.4	0.5	0.5	0.4	0.5
Slate Creek	1.4	1.8	1.6	2.0	2.3	1.8	2.1	2.3	3.0	2.8	2.8	2.5
South Dry Creek	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
St. Anthony	0.2	0.2	0.2	0.2	0.3	0.2	0.3	0.3	0.4	0.3	0.3	0.3
Stateline	12.7	9.9	11.5	13.0	13.9	12.2	14.4	14.4	16.3	14.4	15.0	14.4
Sumas Energy	115.8	118.6	121.3	122.9	123.0	121.9	106.0	90.2	88.7	87.4	114.3	114.1
Summer Falls 1 & 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tenaska Washington Partn	230.6	236.2	241.5	244.7	245.0	242.8	211.1	179.7	176.7	174.0	227.6	227.2
Tiber-Montana	1.6	2.1	1.9	2.4	2.8	2.2	2.5	2.7	3.6	3.3	3.3	3.0
Tieton	4.4	5.8	5.2	6.6	7.6	5.9	6.8	7.4	9.7	9.0	9.0	8.1
Tuttle Ranch (Ravenscroft)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Twin Falls (TFHA)	6.5	8.6	7.6	9.7	11.2	8.6	10.0	10.8	14.2	13.2	13.2	12.0
Twin Reservoirs	1.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0	1.0
U.S. Bankcorp IC1 - IC4	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Upriver	4.6	6.0	5.3	6.8	7.8	6.0	7.0	7.6	9.9	9.2	9.3	8.4
Vaagen Brothers Lumber	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Vansycle Wind Energy Proj	1.1	0.8	1.0	1.1	1.2	1.0	1.2	1.2	1.4	1.2	1.2	1.2
Wapato Drop 2 (#1)	3.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	3.0	3.0	3.0	3.0
Wapato Drop 3 (#1 - 2)	2.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.0	2.0	2.0	2.0
Weeks Falls	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Weyerhaeuser (Springfield)	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6
Wheelabrator Spokane	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
White Creek	8.5	6.6	7.7	8.7	9.3	8.2	9.7	9.7	11.0	9.7	10.1	9.7
Wild Horse Wind	9.7	7.5	8.7	9.9	10.6	9.3	11.0	11.0	12.4	11.0	11.4	11.0
Wilson Lake	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wolverine Creek	2.7	2.1	2.5	2.8	3.0	2.6	3.1	3.1	3.5	3.1	3.2	3.1
WSU Grimes Way Central S	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Yellowstone Energy (BGI)	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6
Total	**11569**	**11699**	**11839**	**11949**	**11972**	**11879**	**10221**	**8571**	**8531**	**8445**	**11537**	**11525**

Uncommitted IPPs

Big Hanaford CC1A-1E	233.4	239.1	244.5	247.7	248.0	245.8	213.6	181.9	178.8	176.1	230.4	230.0
Centralia 1	570.0	570.0	570.0	570.0	570.0	570.0	479.0	388.0	388.0	388.0	570.0	570.0
Centralia 2	670.0	670.0	670.0	670.0	670.0	670.0	563.0	456.0	456.0	456.0	670.0	670.0
Grays Harbor Energy Facilit	611.7	626.8	640.8	649.2	650.0	644.2	559.9	476.7	468.7	461.7	603.8	602.8
Hermiston Power Project	488.8	505.2	519.7	529.4	530.0	522.7	450.5	381.5	372.8	365.5	475.1	476.6
Klamath Cogeneration Proje	442.7	457.5	470.6	479.4	480.0	473.4	408.0	345.5	337.6	331.1	430.3	431.7
Klamath Generation Peaker	47.1	48.2	49.3	49.9	50.0	49.6	45.1	40.8	40.1	39.5	46.4	46.4
Klamath Generation Peaker	47.1	48.2	49.3	49.9	50.0	49.6	45.1	40.8	40.1	39.5	46.4	46.4
Mint Farm	300.2	307.6	314.5	318.6	319.0	316.1	274.8	234.0	230.0	226.6	296.3	295.8
Morrow Power	23.5	24.1	24.6	25.0	25.0	24.8	22.6	20.4	20.0	19.7	23.2	23.2
West Point Treatment Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**3435**	**3497**	**3553**	**3589**	**3592**	**3566**	**3062**	**2565**	**2532**	**2504**	**3392**	**3393**



Idahoans Deserve Clean Energy At A Fair Price

BY LISA GROW
IDAHO POWER
SENIOR VICE
PRESIDENT
OF POWER SUPPLY

Something needs to change about the way alternative energy is priced in Idaho.

Idahoans are already paying hundreds of millions of dollars in excess costs for electricity they may not even need. Unless something is done, they could pay millions more. That's why Idaho Power has asked the Idaho Public Utilities Commission (IPUC) to update the way prices are calculated for the energy **Idahoans are required to buy** from wind, solar and other alternative energy projects.

Federal law requires Idaho Power to buy electricity from independent producers, regardless of whether our customers

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need it or not. To make matters worse, prices for this energy are set far higher than the price of electricity readily available on the open market or from our own resources.

The result? Idaho Power **customers will pay an estimated $850 million** in additional costs associated with these purchases over the next 10 years. Contracts already signed with alternative energy (primarily large-scale wind) producers obligate Idaho Power customers to $4.8 billion in payments over the life of the contracts.

Something needs to change.

Idaho Power has a planning process for determining how to best meet customers' electricity needs now and into the future. We collaborate with community members and various interest groups on our Integrated Resource Plan, which is updated every two years. The plan considers all resource options based on cost, reliability and environmental stewardship. The requirement to buy energy from these producers at inflated prices circumvents this public planning process and results in Idaho Power's customers paying substantially more for their energy.

Idaho Power recently filed testimony with the IPUC recommending changes to the way prices are set for energy from these alternative energy projects. This is an important issue to all Idaho families and business owners. We all want reliable, responsible energy. But we need it at a fair price based on its value.

What can you do?

- Learn more at www.idahopower.com
- Join the conversation at www.getpluggedin.com
- Submit your comments to the Idaho Public Utilities Commission at www.puc.idaho.gov

IDAHO POWER. An IDACORP Company

REQUEST FOR PRODUCTION NO. 65: At page 39 of his rebuttal testimony, Mr. Stokes makes reference to the IRP Advisory Council. Please provide all documents relating to the selection of the current IRP Advisory Council. Are the council members provided with independent, technical staff?

RESPONSE TO REQUEST FOR PRODUCTION NO. 65: No documents exist related to the selection of the IRP Advisory Council ("Council") with the exception of the list of current members listed below that participated in the preparation of the 2011 IRP:

Customer Representatives	
Agricultural Representative	Sid Erwin
Boise State University	John Gardner
Heinz Frozen Foods	Steve Munn
INL	Tom Moriarty
Micron	Michael Bick
Simplot	Don Sturtevant
Public Interest Representatives	
Boise Metro Chamber of Commerce	Bill Connors
Idaho Conservation League	Ben Otto
Idaho Department of Commerce	Lane Packwood
Idaho Office of Energy Resources	John Chatburn
Idaho State House of Representatives	Representative Elaine Smith
Idaho State Senate	Senator Russ Fulcher
Northwest Power and Conservation Council	Jim Yost/Shirley Lindstrom
Oil/Gas Industry Advisor	David Hawk
Snake River Alliance	Ken Miller
Water Issues Advisor	Vince Alberdi
Regulatory Commission Representatives	
Idaho Public Utilities Commission	Rick Sterling
Public Utility Commission of Oregon	Erik Colville

There is routinely some turnover in Council membership between IRP cycles. Idaho Power strives to maintain a balance on the Council between the interests of all the different stakeholders. In the next few weeks the Company expects to finalize the Council membership for its 2013 IRP which begins with the first Council meeting on August 16, 2012.

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No, the Council members are not provided with independent technical staff.

The response to this Request was prepared by M. Mark Stokes, Power Supply Planning Manager, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

AGREEMENT FOR TRANSFER OF OWNERSHIP OF ENVIRONMENTAL ATTRIBUTES

This Agreement for Transfer of Ownership of Environmental Attributes ("Agreement") is entered into this 20th day of May, 2011, between Clark Canyon, LLC, an Idaho Limited Liability Company, ("Clark Canyon") and Idaho Power Company, an Idaho corporation ("Idaho Power" or "Company"), hereinafter sometimes referred to collectively as the "Parties" or individually as a "Party."

WITNESSETH:

WHEREAS, Clark Canyon is the owner and operator of a to-be-built 4.7 megawatt ("MW") small hydro generation project.

WHEREAS, the Parties entered into that certain Firm Energy Sales Agreement between Clark Canyon, LLC and Idaho Power Company dated May 20, 2011 whereby Idaho Power would purchase the energy output of the Facility.

WHEREAS, the FESA Article 8 specifies that ownership of Environmental Attributes is determined by a separate agreement;

WHEREAS, the Parties desire to enter into this Agreement to transfer the ownership of the Environmental Attributes that result from electric generation at the Facility beginning in Contract Year eleven (11) of the FESA.

NOW, THEREFORE, in consideration of the mutual covenants contained herein, the Parties agree as follows:

1. Definitions. The following term as used in this Agreement shall be defined as follows:

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1.1. "Environmental Attributes" means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Facility, and its avoided emission of pollutants. Environmental Attributes include but are not limited to: (1) any avoided emission of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by law, to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere; (3) the reporting rights to these avoided emissions, such as and without limitation, REC (as that term is defined herein) reporting rights. REC reporting rights are the right of a REC owner or purchaser to report the ownership of accumulated RECs in compliance with federal or state law, if applicable, and to a federal or state agency or any other party at the REC owner's/purchaser's discretion, and includes, without limitation, those REC reporting rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present or future federal, state, or local law, regulation or bill, and international or foreign emissions trading program. Environmental Attributes are accumulated on a MWh basis and one REC represents the Environmental Attributes associated with one (1) megawatt hour ("MWh) of energy. Environmental Attributes do not include (i) any energy, capacity, reliability or other power attributes from the Facility, (ii) production tax credits associated with the construction or operation of the Facility and other financial incentives in the form of credits, reductions, or allowances associated with the Facility that are applicable to a state or federal income taxation obligation, (iii) the cash grant in lieu of the investment tax credit pursuant to Section 1603 of the American Recovery and Reinvestment Act of 2009, or (iv) emission reduction credits encumbered or used by the Facility for compliance with local, state, or federal operating and/or air quality permits.

1.2. "Contract Year" shall have the same meaning as defined in the FESA.

1.3. "Facility" shall have the same meaning as defined in the FESA.

1.4. "Renewable Energy Certificate" or "REC" means a certificate, renewable energy credit or any other credit, allowance, Green Tag, or other transferable indicia, howsoever entitled, indicating generation of all renewable energy by the Facility, as determined by any and all federal and/or state law or regulation, and includes all Environmental Attributes arising as a result of the generation of electricity by the Facility. One REC represents the Environmental Attributes associated with the generation of one thousand (1,000) kWh of Net Energy (as that term is defined in the FESA).

2. For good and valuable consideration receipt of which the Parties hereby acknowledge, Clark Canyon agrees to transfer to Idaho Power ownership of all Environmental Attributes associated with the Facility beginning with the first hour of the first day of the 11th Contract Year and for the remaining term of the FESA.

3. Environmental Attribute Accounting and Transfers. The Parties shall cooperate to ensure that all Environmental Attribute certifications, rights and reporting requirements are created, maintained and completed by the responsible Parties.

3.1. Accounting for Environmental Attributes. Each Party, at its sole expense, will be responsible to establish and maintain a Western Renewable Energy Generation Information System ("WREGIS") account or other Environmental Attribute account and/or tracking and reporting system that enables the Environmental Attributes associated with the Facility to be created, certified, validated, transferred and reported.

3.2. Transfer of Ownership Rights to Idaho Power. For the term of the FESA, the Parties shall cooperate, provide further assurances, and take all necessary commercially reasonable actions to document, record, create, effect and enable the transfer of the Environmental Attributes associated with the Facility to Idaho Power's WREGIS account or any other Environment Attribute accounting and tracking system selected by the Parties.

3.3. Ownership Rights. Each Party shall report under Section 1605(b) of the Energy Policy Act of 1992 or under any applicable program only the Environmental Attributes that such Party owns, and shall at all other times refrain from reporting the Environmental Attributes owned by the other Party.

3.4 Right of Peaceful Ownership: Neither Party will cause or suffer to be caused any petition, litigation, action, proceeding or cause, whether before courts, commissions, legislative bodies, tribunals, councils or any other place that would have the effect or purpose to take away or diminish the value of the other's ownership of the Environmental Attributes.

4. Facility Operation. Clark Canyon shall operate the Facility pursuant to commercially reasonable business practices and prudent utility practice so as to not jeopardize the current or future Environmental Attributes created by the Facility.

5. Miscellaneous.

5.1. Several Obligations. Except where specifically stated in this Agreement to be otherwise, the duties, obligations and liabilities of the Parties are to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or impose a trust or partnership duty, obligation or liability on or with regard to either Party. Each Party shall be individually and severally liable for its own obligations under this Agreement.

5.2. Waiver. Any waiver at any time by either Party of its right with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent default or other matter.

5.3. Choice of Law and Venue. This Agreement shall be construed and interpreted in accordance with the laws of the State of Idaho without reference to its choice of law provisions. Venue for any litigation arising out of or related to this Agreement will be in the District Court of The Fourth Judicial District of Idaho in and for the County of Ada.

5.4. Default. If either Party fails to perform any of the terms or conditions of this Agreement (an "Event of Default"), the non-defaulting Party shall cause notice in writing to be given to the defaulting Party, specifying the manner in which such default occurred. If the defaulting Party shall fail to cure such default within sixty (60) days after service of such notice, or if the defaulting Party reasonably demonstrates to the other party the default can be cured within a commercially reasonable time but not within such sixty (60) day period and then fails to diligently pursue such cure, then, the non-defaulting Party may, at its option, terminate this Agreement and/or pursue its legal or equitable remedies.

5.5. Successors and Assigns. This Agreement and all of the terms and provision hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties hereto, except that no assignment hereof by either party shall become effective without the written consent of both Parties being first obtained. Such consent shall not be unreasonably withheld. Notwithstanding the foregoing, any party which Idaho Power may consolidate, or into which it may merge, or to which it may convey or transfer substantially all of its electric utility assets, shall automatically, without further act, and without need of consent or approval by Clark Canyon, succeed to all of Idaho Power's rights, obligations and interests under this Agreement.

5.6. Modification. No modification to this Agreement shall be valid unless it is in writing and signed by both Parties and subsequently approved by the Commission.

5.7. Notices. All written notices under this Agreement will be directed as follows and shall be considered delivered when faxed, emailed and confirmed with deposit in the U. S. Mail, first class, postage prepaid, as follows:

To Clark Canyon:

Original document to:

Clark Canyon Hydro, LLC
C/O Symbiotics, LLC
Kim Johnson
2000 S. Ocean Blvd #703
DelRay Beach, Florida 33438

Telephone: (435) 752-2580

E-mail: vince.lamarra@symbioticsenergy.com
E-mail copy: kim.johnson@riverbankpower.com

To Idaho Power:

Original document to:

Vice President, Power Supply
Idaho Power Company
PO Box 70
Boise, Idaho 83707
Email: Lgrow@idahopower.com

Copy of document to:

Cogeneration and Small Power Production
Idaho Power Company
PO Box 70
Boise, Idaho 83707
E-mail: rallphin@idahopower.com

5.8. Severability. The invalidity or unenforceability of any term or provision of this Agreement shall not affect the validity or enforceability of any other terms or provision and this Agreement shall be construed in all other respects as if the invalid or unenforceable term or provision were omitted.

5.9. Counterparts. This Agreement may be executed in two or more counterparts, each of which shall deemed an original but all of which together shall constitutes one and the same instrument.

5.10. Entire Agreement. Unless otherwise provided for herein, this Agreement constitutes the entire Agreement of the Parties concerning the subject matter hereof and supersedes all prior or contemporaneous oral or written agreements between the Parties concerning the subject matter hereof.

IN WITNESS WHEREOF, The Parties hereto have caused this Agreement to be executed in their respective names on the dates set forth below:

Idaho Power Company	Clark Canyon, LLC.
By Lisa A. Grow	By Kim L Johnson
Lisa A Grow Sr. Vice President, Power Supply	Kim L Johnson Executive Vice Pres, Dept Business Development
Dated 5.20.11	Dated 5-18-11
"Idaho Power"	"Seller"

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projects will become increasingly difficult without imminent passage of federal clean energy legislation. A federal incentive backing this project, the Treasury Grant, is expiring at year's end. Extending that program and other federal incentives would provide the long-term certainty that investors and manufacturers such as GE need to ensure continued expansion of renewable energy throughout the country."

Construction of the Idaho project is well under way. Workers are delivering wind turbine blades, towers and other components; they are installing foundations and footings for the turbine towers, building access roads, preparing interconnection lines with Idaho Power's grid and readying a site for a new power substation. The project will use GE's 1.5-megawatt turbines, over 13,500 of which have been installed worldwide. In addition to supplying the turbines, GE will provide operational and maintenance services.

"We have worked long and hard with our partners, including local landowners, contractors and suppliers, to create this historic project," said James Carkulis, president and CEO of Exergy, which conceptualized, planned and engineered the project over the last five years. "We wanted from the outset to make the right kind of difference in the lives of the people who live here, and we take great pride in our corporate responsibility, sensitivity to the local environment, and promotion of traditional Idaho and community values."

Lisa Grow, Idaho Power's senior vice president of Power Supply, stated: "Clean, renewable energy has been Idaho Power's focus since its founding nearly 100 years ago. We started with hydroelectric power and, through diligent planning, have expanded into the next generation of alternative energy sources, from this new wind project to solar, geothermal and biomass. Our balanced generation portfolio is not only the environmentally responsible way of doing business but ensures we can offer our customers some of the lowest rates in the nation while providing reliable energy services."

About GE Energy Financial Services
GE Energy Financial Services' experts invest globally across the capital spectrum in essential, long-lived and capital-intensive energy assets that meet the world's energy needs. In addition to capital, GE Energy Financial Services offers the best of GE's technical know-how, technology innovation, financial strength and rigorous risk management. Based in Stamford, Connecticut, the GE business unit helps its customers and GE grow through new investments, strong partnerships and optimization of its $21 billion in assets. For more information, visit www.geenergyfinancialservices.com.

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press release

FARMING THE WIND NEAR THE OREGON TRAIL: IDAHO'S GOVERNOR, GE AND PARTNERS LAUNCH STATE'S LARGEST WIND POWER PROJECT

BLISS, Idaho, Aug. 24, 2010 – Transforming arid farmland into land yielding clean power and jobs, Gov. C.L. "Butch" Otter joined executives of GE (NYSE: GE) and its partners today to celebrate the start of construction of the state's largest wind power project, 10 miles from the Oregon Trail where American pioneers pushed westward across the continent.

The governor – joined by project investors GE Energy Financial Services, Reunion Power, Exergy Development Group and Atlantic Power Corp. (TSX:ATP, NYSE:AT) – signed a turbine blade in Bliss to celebrate the new jobs and economic development this project is bringing to the area. The 183-megawatt,122-turbine project comprises 11 wind farms, spread across 10,000 acres of active and inactive farmland in southern Idaho's Magic Valley. The valley was a predominant migration route as part of the Oregon Trail in the 19th century, and is becoming a critical renewable energy corridor in the 21st century.

The wind energy project, initiated by Exergy Development Group and slated for completion by year's end, is expected to create 175 construction jobs as well as permanent employment for operations and maintenance. In addition to the people employed directly, a National Renewable Energy Laboratory model estimates that a wind project of this size would typically support the equivalent of 2,200 full-time jobs in the United States for one year—about half of which would be in-state—and create 25 permanent jobs. The project also benefits the environment: It will produce enough power for 39,700 average Idaho homes and—according to US Environmental Protection Agency methodology—avoid 331,000 short tons a year in greenhouse gas emissions. That's the equivalent of taking about 57,000 cars off the road.

"The renewable energy industry is breathing new life into the Idaho frontier," said Gov. Otter. "We're aggressively harnessing our abundant natural resources for growth because that helps our economy, generating not only electricity but career opportunities right here at home."

GE Energy Financial Services, Atlantic Power, and project developer Exergy own non-managing member equity interests in the nearly $500 million Idaho Wind project. Reunion Power holds the managing member equity interest and serves as the project's manager. The wind farms will sell all of their power to Idaho Power Company under 20-year agreements. Once completed, the portfolio is expected to qualify for the federal Treasury Grant program designed to stimulate renewable energy projects.

"While we are delighted to embark on this new renewable energy project in Idaho," said GE Energy Financial Services President and CEO Alex Urquhart, "we are concerned that such

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For the second 10 years of the agreement (2018–2027), Idaho Power is entitled to 51 percent of the total RECs generated by the project.

Neal Hot Springs Geothermal Project

In May 2010, the IPUC approved a PPA for approximately 22 MW of nameplate generation from the Neal Hot Springs Geothermal Project located in eastern Oregon. The Neal Hot Springs project is under development and is expected to begin commercial operations in 2012. Under the PPA, Idaho Power receives all the RECs from the project.

Clatskanie Energy Exchange

In September 2009, Idaho Power and the Clatskanie People's Utility District (Clatskanie PUD) in Oregon entered into an energy exchange agreement. Under the agreement, Idaho Power receives the energy as it is generated from the newly constructed 18-MW power plant at Arrowrock Dam on the Boise River; and in exchange, Idaho Power provides Clatskanie PUD energy of equivalent value delivered seasonally—primarily during months when Idaho Power expects to have surplus energy. An energy bank account is maintained to ensure a balanced exchange between the parties where the energy value will be determined using the Mid-Columbia market price index. The Arrowrock project began generating in January 2010, and the agreement term extends through 2015. Idaho Power also retains the right to renew the agreement through 2025. The Arrowrock project is expected to produce approximately 81,000 MWh annually.

Public Utility Regulatory Policies Act

In 1978, Congress passed PURPA requiring investor-owned electric utilities to purchase energy from any qualifying facility (QF) that delivers energy to the utility. A QF is defined by FERC as a small renewable-generation project or small cogeneration project. Individual states were tasked with establishing the PPA terms and conditions, including price, that each state's utilities are required to pay as part of the PURPA agreements. Because Idaho Power operates in both Idaho and Oregon, the company must adhere to both the IPUC rules and regulations for all PURPA facilities located in the state of Idaho, and the OPUC rules and regulations for all PURPA facilities located in the state of Oregon. The rules and regulations are similar, but not identical, for the two states. Because Idaho Power cannot accurately predict the level of future PURPA development, only signed contracts are accounted for in Idaho Power's resource planning process.

Generation from PURPA contracts has to be forecasted early in the IRP planning process to update the load and resource balance. The forecast used in the 2011 IRP was completed in September 2010 and did not include approximately 500 MW of wind contracts that were signed in late 2010. Because Idaho Power's future resource needs are driven by capacity requirements and not energy, the exclusion of these new contracts does not have a material impact on the 2011 IRP. At the 5-percent peak-hour capacity factor used for wind resources for planning purposes, the 500 MW of PURPA wind contracts represent only 25 MW of capacity for peak-hour planning.

As of March 31, 2011, Idaho Power had 127 PURPA contracts with independent developers for approximately 1,190 MW of nameplate capacity. The PURPA generation facilities consist of low-head hydroelectric projects on various irrigation canals, cogeneration projects at industrial facilities, wind projects, anaerobic digesters, landfill gas, wood-burning facilities, solar projects, and various other small, renewable-power projects. Of the 127 contracts, 91 were on line as of March 31, 2011, with a cumulative nameplate rating of approximately 491 MW. Figure 3.4 shows the total nameplate capacity of each resource type under contract. Figure 3.4 includes 294 MW from 13 PURPA wind contracts that were recently disapproved by the IPUC. Additional details on these contracts are presented in the next section.

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REQUEST FOR PRODUCTION NO. 66: On page 46 of his rebuttal testimony Mr. Stokes states that "The Commission has specifically found this [liquidated damages] requirement to be in the public interest and a just and reasonable requirement of the contracting process." Please provide copies of, or citations to, where the Commission "specifically" made those findings.

RESPONSE TO REQUEST FOR PRODUCTION NO. 66: Please See Idaho Power's Legal Brief filed in this proceeding on July 20, 2012, pp. 27-32.

> Delay liquidated damages provisions have been included in PURPA FESA contracts approved by the Commission since at least 2007. See, Case No. IPC-E-06-36. In addition, one of the first Commission approved FESAs to contain terms requiring the project to post liquid security was the FESA for Cassia Gulch Wind Park and Tuana Springs Energy, Case No. IPC-E-09-24. In that case the Commission approved provisions requiring the posting of liquid security in the amount of $20 per kW of project capacity.
>
> The Commission considered and approved provisions providing for the posting of liquid security in the amount of $20 per kW of project capacity in at least four other PURPA FESAs. See, Case No. IPC-E-09-18, IPC-E-09-19, IPC-E-09-20, IPC-E-09-25. The Commission has since analyzed and approved provisions requiring the posting of liquid security in the amount of $45 per kW of nameplate capacity in at least twenty-seven different PURPA FESAs. See, Case No. IPC-E-10-02, IPC-E-10-05, IPC-E-10-15, IPC-E-10-16, IPC-E-10-17, IPC-E-10-18, IPC-E-10-19, IPC-E-10-22, IPC-E-10-26, IPC-E-10-37, IPC-E-10-38, IPC-E-10-39, IPC-E-10-40, IPC-E-10-41, IPC-E-10-42, IPC-E-10-43, IPC-E-10-44, IPC-E-10-45, IPC-E-10-47, IPC-E-10-48, IPC-E-10-49, IPC-E-10-50, IPC-E-11-09, IPC-E-11-10, IPC-E-11-25, IPC-E-11-26, and IPC-E-11-27. In approving the change in the amount of delay damage security that is acceptable for such contracts from $20 to $45 per kW of nameplate capacity, the Commission specifically found such delay security to be reasonable, necessary, and not to be punitive. Order No. 31034, p. 3-4, Case No. IPC-E-10-02 (2010).

Idaho Power's Legal Brief, Case No. GNR-E-11-03, pp. 27-28.

The response to this Request was prepared by Donovan E. Walker, Lead Counsel, Idaho Power Company.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR APPROVAL OF ITS FIRM ENERGY SALES AGREEMENT WITH CARGILL INCORPORATED	)))))	**CASE NO. IPC-E-10-02** **ORDER NO. 31034**

On January 29, 2010, Idaho Power Company ("Idaho Power" or "Company") filed an Application with the Commission seeking approval, in accordance with *Idaho Code* § 61-503, RP 52 and the applicable provisions of the Public Utility Regulatory Policies Act of 1978, of its Firm Energy Sales Agreement with Cargill Incorporated ("Cargill") under which Cargill would sell and Idaho Power would purchase electric energy generated by the Bettencourt Dry Creek Biofactory ("Facility") located near Hansen, Idaho. *Application* at 1.

On February 25, 2010, the Commission issued a Notice of Application and Modified Procedure with a 21-day comment period. *See* Order No. 31014. Commission Staff was the only party to submit comments within the established comment period.

THE APPLICATION

"On January 22, 2010, Idaho Power and Cargill entered into a Firm Energy Sales Agreement ("Agreement"). . . ." *Id.* at 2, Attachment No. 1. The Agreement is for a 10-year term and utilizes "the Non Levelized Published Avoided Cost Rates as currently established by the Commission for energy deliveries of less than 10 average megawatts ("MW")." *Id.* at 3

Idaho Power states that Cargill is an existing Schedule 86 partner providing energy to the Company and that it will utilize the "compliance data (i.e., nameplate capacity rating, engineering certification, insurance certificates, etc.) previously provided under the Schedule 86 requirements" to review and use for compliance with this Agreement if applicable. *Id.*

"The nameplate rating of this Facility is 2.25 MW." *Id.* "Cargill will be required to provide data on the Facility that Idaho Power will use to confirm that under normal and/or average conditions the Facility will not exceed 10 average MW on a monthly basis." *Id.* Any energy that exceeds 10 aMW per month, and that does not exceed the Maximum Capacity Amount, will be accepted but not purchased or paid for by Idaho Power. *Id.*

The Scheduled Operation Date for the Agreement is 30 days after the approval of the Agreement by the Commission. *Id.* The Agreement includes a formula for the assessment and

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calculation of Delay Liquidated Damages and associated Delay Security provisions if Cargill fails to achieve the targeted Operation Date. *Id.*; *see also* Article V of the Agreement. The Agreement states that it is effective once "the Commission has approved all of the Agreement's terms and conditions and declared that all payments Idaho Power makes to Cargill for purchases of energy will be allowed as prudently incurred expenses for ratemaking purposes." *Id.* at 4.

The Agreement places various conditions and requirements in order for Idaho Power to accept energy from Cargill. *Id.* Idaho Power states that if the Commission approves the Agreement the effective date of the Agreement will be January 22, 2010. *Id.*

The Agreement includes non-levelized published avoided cost rates consistent with past applicable IPUC Orders. *Id.* Interconnections with the Facility and applicable charges have been completed in accordance with the parties' existing Schedule 86 agreement transacted in 2008. *Id.*

STAFF COMMENTS AND RECOMMENDATION

Staff reviewed the Agreement and found "that the rates contained therein are consistent with the currently-approved non-levelized published avoided cost rates for projects smaller than 10 aMW." Staff Comments at 2. Staff noted that, with one exception, the essential terms and conditions "included in the Agreement are identical to those contained in recent PURPA contracts approved by the Commission." *Id.* at 2-3.

Staff remarked that the amount of Delay Security required under the contract was the one unique feature that distinguished this Agreement from other similar types of agreements presented by Idaho Power to the Commission for approval. *Id.* at 3. The amount of Delay Security in this Agreement is "equal to the greater of $45 per kW or the sum of three months' estimated revenue." *Id.* The total Delay Security is estimated to be approximately $101,250. *Id.* In previous contracts, the Company required Delay Security in the amount of $25 per kW. *Id.* "Delay Liquidated Damages would be assessed if the Facility failed to come online within 90 days following the Scheduled Operation Date." *Id.*

Staff commented that Idaho Power's Firm Energy Sales Agreements for PURPA projects did not include a Delay Liquidated Damages penalty until around 2006. *Id.* Idaho Power has included the penalty as the result of several PURPA projects failing to achieve their scheduled operation date. *Id.*

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The increase in the amount of Delay Security arose from Idaho Power's estimation that $25 per kW did not provide adequate damages for delay or a sufficient incentive for project owners to actually meet the scheduled operation date. *Id.* Idaho Power settled upon the $45 per kW after researching "the security levels required by ten other electric utilities throughout the U.S. in their renewable energy procurements and contracts." *Id.* Only one of the utilities sampled required security less than $25 per kW, while the other nine utilities required security of at least $50 per kW. *Id.* Staff believes that the $45 per kW amount is reasonable because it is "high enough to cover possible damages and to motivate owners to complete projects on time, yet not so high as to make it too difficult for owners and developers to post the security and obtain project financing." *Id.*

Staff also noted that delay security and damages for the Bettencourt Dry Creek project will not be an issue because the Facility is "already online and selling to Idaho Power under a Schedule 86 agreement. . . ." *Id.* Nevertheless, Staff commented on the deviation from prior agreements because Staff believes that "Idaho Power is seeking endorsement of the higher security requirement in this Agreement with the intent of including it in future contracts." *Id.* at 4.

Staff recommended that the Commission approve Idaho Power's Firm Energy Sales Agreement with Cargill and declare that all payments Idaho Power makes to Cargill for purchases of energy be deemed prudently incurred expenses for ratemaking purposes. *Id.*

COMMISSION DECISION AND FINDINGS

The Commission has reviewed and considered the filings in Case No. IPC-E-10-02, including the underlying Agreement submitted for approval and Staff comments. Idaho Power has presented a Firm Energy Sales Agreement with Cargill for the Commission's consideration. The Agreement stipulates that Cargill will continue to provide and Idaho Power will continue to purchase 10 aMW or less of electric energy on a monthly basis.

The Commission acknowledges Staff's comments regarding the relative increase in the amount of delay security and liquidated damages contemplated in this Agreement. The Commission finds that the increase in the Delay Security included in this Agreement is reasonable and necessary. Adequate Delay Security acts not only as an incentive for PURPA project owners to complete their projects on time, but it can also mitigate any additional costs which might arise when a utility is forced to purchase substitute power on the open market.

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However, the Commission reiterates its prior admonition that "such provisions calling for delay security should not be punitive" and "should constitute a fair and reasonable offset of a regulated utility's estimated increase in power supply costs attributable to the PURPA supplier's failure to meet its contractually scheduled operation date." Order No. 30608.

Accordingly, the Commission finds that Idaho Power's Agreement to purchase electric energy from Cargill's Bettencourt Dry Creek Biofactory contains acceptable contract terms, including the non-levelized published rates previously approved by the Commission. *See* Order No. 30480. The Commission also finds that payments made by Idaho Power pursuant to the terms of the Agreement are deemed prudently incurred expenses for ratemaking purposes.

CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over Idaho Power, an electric utility, and the issues raised in this matter pursuant to the authority and power granted it under Title 61 of the Idaho Code and the Public Utility Regulatory Policies Act of 1978 ("PURPA").

The Commission has authority under PURPA and the implementing regulations of the Federal Energy Regulatory Commission ("FERC") to set avoided costs, to order electric utilities to enter into fixed-term obligations for the purchase of energy QFs and to implement FERC rules.

ORDER

IT IS HEREBY ORDERED that Idaho Power Company's Firm Energy Sales Agreement with Cargill Incorporated is approved.

THIS IS A FINAL ORDER. Any person interested in this Order (or in issues finally decided by this Order) may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration any other person may cross-petition for reconsideration. *See Idaho Code* § 61-626.

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DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 1st day of April 2010.

JIM D. KEMPTON, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

MACK A. REDFORD, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

O:IPC-E-10-02_np2

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR APPROVAL OF A FIRM ENERGY SALES AGREEMENT WITH YELLOWSTONE POWER, INC. FOR THE SALE AND PURCHASE OF ELECTRIC ENERGY.	**CASE NO. IPC-E-10-22** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its attorney of record, Kristine A. Sasser, Deputy Attorney General, and in response to the Notice of Filing and Notice of Modified Procedure issued in Order No. 32573 on June 19, 2012, in Case No. IPC-E-10-22, submits the following comments.

BACKGROUND

On May 4, 2004, the Commission approved a Firm Energy Sales Agreement (FESA) between Idaho Power and Renewable Energy of Idaho, Inc. ("Renewable Energy") for a 17.5 megawatt (MW) biomass generating facility to be located at the old Boise Cascade Plant site near Emmett, Idaho. Order No. 29487. The FESA subsequently went into default and was terminated by Idaho Power after Renewable Energy failed to meet its scheduled operation date. Renewable Energy claimed its inability to meet the scheduled operation date was due to reasons beyond its control. Idaho Power determined that the project had incurred damages in the amount of $106,804 for Renewable Energy's non-performance. Renewable Energy was unable to pay the assessed damages.

On August 13, 2010, Idaho Power filed an Application with the Commission requesting approval of a 15-year FESA between Idaho Power and Yellowstone Power for an 11.7 MW biomass fueled combined heat and power generator located at the same site as the Renewable Energy project. Richard Vinson, a principal of Yellowstone Power, was also a principal of Renewable Energy. Mr. Vinson agreed, as part of the Yellowstone FESA negotiations, to pay the non-performance damages of the Renewable Energy FESA as an offset to the energy payments Yellowstone was to receive in its FESA. On November 2, 2010, the Commission approved the FESA between Idaho Power and Yellowstone, including the payment by Yellowstone of Renewable Energy's $106,804 in non-performance damages. Order No. 32104. Yellowstone chose a scheduled operation date of December 31, 2011. In addition, the FESA required Yellowstone to post a delay liquidated damages deposit in the amount of $450,000. Yellowstone timely posted this required deposit in the form of a Letter of Credit.

Yellowstone has failed to achieve its December 31, 2011, scheduled operation date. On May 3, 2012, Idaho Power sent Yellowstone a notice of material breach for failing to achieve its scheduled operation date and stating that it would collect on the Letter of Credit by May 10, 2012, if Yellowstone failed to cure the material breach. Yellowstone responded by alleging that a *force majeure* event had occurred. Settlement discussions between the parties ensued.

On May 31, 2012, Idaho Power Company and Yellowstone Power, Inc. filed a motion requesting that the Commission accept a Settlement Stipulation ("Settlement") entered into between the parties. The Settlement Stipulation provides for termination of the FESA between Idaho Power and Yellowstone Power and mutual release of any future claims or causes of action between the parties. Yellowstone agrees to pay Idaho Power $200,000 for its material breach of the FESA, which amount includes Renewable Energy's pre-existing debt of $106,804. If Yellowstone fails to make the $200,000 payment then Yellowstone agrees to allow Idaho Power to draw on the current $450,000 Letter of Credit. Idaho Power and Yellowstone state that the Settlement Stipulation is in the public interest and that all of its terms and conditions are fair, just, and reasonable.

STAFF ANALYSIS

Staff believes that because the project has not achieved operation within 90 days of the scheduled operation date, the project is in material breach and Idaho Power is entitled to terminate the FESA. In addition, Article 5.3 of the FESA specifies that delay damages of $45 per kilowatt maximum capacity ($45 x 10,000 kW = $450,000) are due and payable to Idaho Power as delay liquidated damages. Idaho Power provided notice to the project of the material breach, and termination of the FESA, as well as the utility's request for payment of the $450,000 delay liquidated damages. The project responded to the notification of material breach with a claim of *force majeure* regarding its non-performance in the contract, as well as a draft complaint for Idaho District Court challenging the legality of the liquidated damages in the contract.

Yellowstone, in its May 15, 2012 letter to Idaho Power alleges that conditions beyond its control have made it impossible to complete the project and achieve the scheduled operation date specified in the FESA. Yellowstone cites the following conditions that have prevented construction of the facility:

- **Availability of Financing** – Yellowstone created an extensive financing package, employed lending specialists, and marketed to a wide variety of local/national banks, venture capitalist, private equity, and hedge funds related to this project. Despite these efforts, the unpredictable change in lending protocols following the banking crisis and resulting extended national economic recession restricted the availability of financing funds for projects such as Yellowstone Power and funds became severely limited.

- **1603 Grant In-Lieu Credit** – The Section 1603 grant in lieu credit adversely impacted conventional lending for projects such as Yellowstone Power by attracting predatory investors to the market. Combined with the unpredictable change in conventional lending protocols, available financing was further reduced.

- **Renewable Energy Credits** – Due to the unexpected prolific installation of wind power experienced by many utilities, the value of renewable energy credits (RECs) decreased dramatically. The revenue contemplated by Yellowstone Power from the sale of RECs was adversely affected by the installation of wind generation.

- **Emerald Forest Sawmill** – Significant revenue and fuel sourcing was contemplated from the Emerald Forest Sawmill. This facility experienced significant operating problems during its start-up and eventually had to seek protection under Chapter 11 Bankruptcy. The loss of this revenue and fuel source had a significant impact on the ability of the project to attract financing due to its close proximity to the proposed Yellowstone Power project.

Yellowstone alleges that the combination of changed conditions are beyond its control and constitute an event of *force majeure*.

For reference, the terms of the FESA relating to *force majeure* are repeated below.

ARTICLE XIV: FORCE MAJEURE

14.1 As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the control of the Seller or of Idaho Power which, despite the exercise of due diligence, such Party is unable to prevent or overcome. Force Majeure includes, but is not limited to, acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, or changes in law or regulation occurring after the effective date, which, by the exercise of reasonable foresight such party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome. If either Party is rendered wholly or in part unable to perform its obligations under this Agreement because of an event of Force Majeure, both Parties shall be excused from whatever performance is affected by the event of Force Majeure, provided that:

(1) The non-performing Party shall, as soon as is reasonably possible after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence.
(2) The suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure.
(3) No obligations of either Party which arose before the occurrence causing the suspension of performance and which could and should have been fully performed before such occurrence shall be excused as a result of such occurrence.

In response to production requests, Idaho Power states that it does not believe that Yellowstone has provided evidence that a *force majeure* event has occurred that would provide the project relief from performance as required by the contract. Staff agrees. The inability of Yellowstone to obtain financing, the decrease in value of RECs, and the bankruptcy of the associated Emerald Forest Sawmill are not the types of things Staff believes are envisioned by the *force majeure* provisions of the FESA.

Staff believes that Idaho Power is entitled to collection of the full amount of the Delay Liquidated Damages ($450,000), in addition to the pre-existing debt of $106,804. Under the terms of section 5.6 of the contract, the parties have agreed that the damages Idaho Power would incur due to delay in the facility achieving the scheduled operation date would be difficult or impossible to predict with certainty, and that the delay liquidated damages are an appropriate approximation of such damages.

Exhibit ______ Page 4 of 7
Simplot, Exergy, Clearwater
On Cross Examination

However, Idaho Power believes that the actual collection of those damages could require additional legal proceedings prior to the Company being able to secure full payment for the damages. As noted earlier, Yellowstone has threatened to file a complaint in Idaho District Court challenging the legality of the liquidated damages in the contract. Yellowstone might argue that the actual damages incurred by Idaho Power could be quantified at less than the $450,000 delay liquidated damages amount specified in the contract.

The proposed Settlement collects $106,804 of previously uncollectable damages from a defaulted agreement and provides approximately $93,196 in damages for default of the current agreement. Consequently, the proposed settlement amount falls $356,804 short of the $556,804 amount Staff believes is rightfully owed by Yellowstone to Idaho Power pursuant to the terms of the FESA.

Nonetheless, the proposed Settlement eliminates the uncertainty and additional cost and resources necessary to litigate the termination of the agreement and validity of the delay liquidated damages. While Staff would normally be reluctant to recommend approval of a settlement that appears inconsistent with the express terms of the contract, Staff recognizes that the current circumstances may support acceptance of the proposed Settlement. Currently, electric market prices are far below the avoided cost rates specified in the contract. Consequently, the actual damages to Idaho Power as a result of contract default are likely minimal, and in fact, Idaho Power could arguably be better off because Yellowstone has defaulted. The terms of the proposed Settlement acknowledge some liability for Yellowstone's default while also acknowledging some uncertainty about the actual amount of damages to Idaho Power. Approval of the proposed Settlement will also avoid litigation. Consequently, Staff believes that the proposed Settlement is in the public interest.

RECOMMENDATIONS

Staff recommends approval of the Settlement Stipulation between Idaho Power and Yellowstone Power.

Exhibit ______ Page 5 of 7
Simplot, Exergy, Clearwater
On Cross Examination

Respectfully submitted this 10TH day of July 2012.

Kristine A. Sasser

Kristine A. Sasser
Deputy Attorney General

Technical Staff: Rick Sterling

i:umisc:comments/ipce10.22ksrps comments

Exhibit ______ Page 6 of 7
Simplot, Exergy, Clearwater
On Cross Examination

FIRM ENERGY SALES AGREEMENT
(Greater than 10 aMW)

Project Name: Dynamis Ada County Landfill Project

Project Number: 21615400

THIS AGREEMENT, entered into on this 16th day of November, 2011 between Dynamis Energy, LLC, an Idaho limited liability company (Seller), and IDAHO POWER COMPANY, an Idaho corporation (Idaho Power), hereinafter sometimes referred to collectively as "Parties" or individually as "Party."

WITNESSETH:

WHEREAS, Seller will design, construct, own, maintain and operate an electric generation facility; and

WHEREAS, Seller wishes to sell, and Idaho Power is willing to purchase, firm electric energy produced by the Seller's Facility.

THEREFORE, In consideration of the mutual covenants and agreements hereinafter set forth, the Parties agree as follows:

ARTICLE I: DEFINITIONS

As used in this Agreement and the appendices attached hereto, the following terms shall have the following meanings:

1.1 "Business Hours" – Daily hours of 8:00 AM to 5:00 PM Mountain Time, Monday through Friday excluding New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas and any other Idaho Power observed holiday.

1.2 "Commission" - The Idaho Public Utilities Commission.

1.3 "Contract Year" - The period commencing each calendar year on the same calendar date as the Operation Date and ending 364 days thereafter.

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Dynamis Energy
On Cross Examination

Example 2 - The Hourly Energy Production amount specified in Appendix E for January, hour 8 is 20 MW. If Declared Suspension of Energy Deliveries is initiated by the Seller and accepted by Idaho Power that results in total shutdown of the Facility, the Hourly Energy Production will be reduced to 0 MW for this hour and any other hours in which the Declared Suspension of Energy Deliveries is in effect.

This adjusted Hourly Energy Production amount will be used in applicable Surplus Energy calculations and performance calculations for only the specific hour in which Idaho Power was excused from accepting the Seller's Net Energy or the Declared Suspension of Energy Deliveries is in effect.

6.3 Beginning with the first day of the seventh (7^{th}) month after the Operation Date, unless excused by an event of Force Majeure, a Forced Outage, or as Scheduled Maintenance, Seller delivers hourly Net Energy to Idaho Power that exceeds plus or minus 10% of the Hourly Energy Production amounts specified in Appendix E for more than 1) Ten (10) consecutive hours, or 2) Seventy two (72) hours in any one calendar month the applicable energy price per MWh shall be reduced by fifteen percent (15%) for all Net Energy and Surplus Energy delivered to Idaho Power for all hours beginning with the first hour after either of these criteria has been met and the reduced energy payments rate shall stay in effect a period of seven (7) days.

6.3.1 If during this seven (7) day period, either of these criteria are again met, a new seven (7) day period of reduced energy payments will begin with the first hour after the criteria has been met.

6.4 Unless excused by an event of Force Majeure, Forced Outage, or Scheduled Maintenance Seller's failure to deliver 30,000 MWh in any Contract Year shall constitute an event of default.

ARTICLE VII: PURCHASE PRICE AND METHOD OF PAYMENT

7.1 Heavy Load Purchase Price – For all Heavy Load Energy accepted by Idaho Power, Idaho Power will pay the non-levelized Heavy Load Purchase Price as specified in Appendix F.

7.2 Holiday Standard Purchase Price – For all Holiday Standard Energy accepted by Idaho Power, Idaho Power will pay the non-levelized Holiday Standard Purchase Price as specified in Appendix F.

7.3 Light Load Energy Price – The Seller does not intend to produce and deliver any Light Load Energy to Idaho Power. Any Light Load Energy produced by the Seller and delivered to Idaho Power may 1) be accepted by Idaho Power at no cost to Idaho Power, or 2) Idaho Power may curtail all Light Load Energy deliveries with no notice provided to the Seller, or 3) the Seller and Idaho Power may mutually agree to terms and conditions of Light Load Energy deliveries prior to the delivery of Light Load Energy. The mutual agreement will specify at minimum the pricing, hours and quantity of Light Load Energy to be delivered to Idaho Power.

10PM-
7AM

7.3.1 The Party requesting Light Load Energy deliveries shall provide written notification to the other Party during Business Hours. This notification shall include desired hours of energy deliveries and proposed energy price, the other party shall then respond within a reasonable period of time during Business Hours.

7.3.2 Upon mutual agreement, the requesting Party shall provide a written document authorized and executed by an appropriate representative. This document must include the mutually agreed upon pricing, hours of delivery and other required terms and conditions. The other Party shall then within a reasonable time, review and execute the provided documentation if the conditions are acceptable.

7.3.3 Only after the written document has been executed by both Parties shall an exception to Light Load Energy deliveries as specified in paragraph 7.3 exist.

7.4 Surplus Energy Price - For all Surplus Energy, Idaho Power shall pay to the Seller the lower of the current month's Market Energy Reference Price or eighty-five percent (85%) of the Holiday Standard Purchase Price.

7.5 Payment Due Date – Undisputed Energy payments, less any payments due to Idaho Power will be disbursed to the Seller within thirty (30) days of the date which Idaho Power receives and accepts the documentation of the monthly Net Energy actually delivered to Idaho Power as specified in Appendix A.

APPENDIX E

HOURLY ENERGY PRODUCTION

This table is a list of hourly energy amounts (measured in MWs) for each hour of a twenty-four (24) hour period in each month that will be applied to all days of the month.

Hour	Jan (MW)	Feb (MW)	Mar (MW)	Apr (MW)	May (MW)	Jun (MW)	Jul (MW)	Aug (MW)	Sep (MW)	Oct (MW)	Nov (MW)	Dec (MW)
1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	20	20	20	20	20	20	20	20	20	20	20	20
8	20	20	20	20	20	20	20	20	20	20	20	20
9	20	20	20	20	20	20	20	20	20	20	20	20
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21	20	20	20	20	20	20	20	20	20	20	20	20
22	20	20	20	20	20	20	20	20	20	20	20	20
23	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0
Daily	320	320	320	320	320	320	320	320	320	320	320	320

APPENDIX F

MONTHLY PURCHASE PRICES

	Mills per Kwh	
Month/Year	**Heavy Load Purchase Price**	**Holiday Standard Purchase Price**
Jan-12	$84.27	$81.05
Feb-12	$85.76	$81.03
Mar-12	$81.15	$76.88
Apr-12	$76.70	$73.32
May-12	$69.70	$63.39
Jun-12	$71.77	$64.29
Jul-12	$83.55	$77.70
Aug-12	$87.83	$81.28
Sep-12	$90.25	$82.51
Oct-12	$84.52	$81.19
Nov-12	$87.90	$84.82
Dec-12	$86.69	$82.30
Jan-13	$86.11	$82.01
Feb-13	$87.75	$83.51
Mar-13	$83.19	$79.45
Apr-13	$78.68	$74.02
May-13	$71.21	$64.51
Jun-13	$73.83	$67.88
Jul-13	$85.47	$79.40
Aug-13	$89.91	$83.36
Sep-13	$91.58	$82.47
Oct-13	$83.94	$80.29
Nov-13	$88.88	$84.40
Dec-13	$88.88	$86.14
Jan-14	$87.76	$82.96
Feb-14	$89.40	$84.87
Mar-14	$85.60	$81.15
Apr-14	$80.92	$75.56
May-14	$72.80	$66.01
Jun-14	$76.15	$69.27
Jul-14	$87.08	$81.11
Aug-14	$91.69	$84.96
Sep-14	$94.41	$86.47

EXHIBIT ______, Page 5 of 5
Dynamis Energy
On Cross Examination

FIRM ENERGY SALES AGREEMENT
(Greater than 10 aMW)

Project Name: Dynamis Ada County Landfill Project

Project Number: 21615400

THIS AGREEMENT, entered into on this 16th day of November, 2011 between Dynamis Energy, LLC, an Idaho limited liability company (Seller), and IDAHO POWER COMPANY, an Idaho corporation (Idaho Power), hereinafter sometimes referred to collectively as "Parties" or individually as "Party."

WITNESSETH:

WHEREAS, Seller will design, construct, own, maintain and operate an electric generation facility; and

WHEREAS, Seller wishes to sell, and Idaho Power is willing to purchase, firm electric energy produced by the Seller's Facility.

THEREFORE, In consideration of the mutual covenants and agreements hereinafter set forth, the Parties agree as follows:

ARTICLE I: DEFINITIONS

As used in this Agreement and the appendices attached hereto, the following terms shall have the following meanings:

1.1 "Business Hours" – Daily hours of 8:00 AM to 5:00 PM Mountain Time, Monday through Friday excluding New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas and any other Idaho Power observed holiday.

1.2 "Commission" - The Idaho Public Utilities Commission.

1.3 "Contract Year" - The period commencing each calendar year on the same calendar date as the Operation Date and ending 364 days thereafter.

limits equal to $1,000,000, each occurrence, combined single limit. The deductible for such insurance shall be consistent with current Insurance Industry Utility practices for similar property.

13.2.2 The above insurance coverage shall be placed with an insurance company with an A.M. Best Company rating of A- or better and shall include:

(a) An endorsement naming Idaho Power as an additional insured and loss payee as applicable; and

(b) A provision stating that such policy shall not be canceled or the limits of liability reduced without ten (10) days' prior written notice to Idaho Power.

13.3 Seller to Provide Certificate of Insurance - As required in paragraph 4.1.5 herein and annually thereafter, Seller shall furnish Idaho Power a certificate of insurance, together with the endorsements required therein, evidencing the coverage as set forth above.

13.4 Seller to Notify Idaho Power of Loss of Coverage - If the insurance coverage required by paragraph 13.3 shall lapse for any reason, Seller will immediately notify Idaho Power in writing. The notice will advise Idaho Power of the specific reason for the lapse and the steps Seller is taking to reinstate the coverage. Failure to provide this notice and to expeditiously reinstate or replace the coverage will constitute a Material Breach of this Agreement.

ARTICLE XIV: FORCE MAJEURE

14.1 As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the control of the Seller or of Idaho Power which, despite the exercise of due diligence, such Party is unable to prevent or overcome. Force Majeure includes, but is not limited to, acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, or changes in law or regulation occurring after the effective date, which, by the exercise of reasonable foresight such party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome. Force Majeure does not include disruptions or curtailment of the Facility's fuel supply that are the result of actions or inactions by the fuel supplier or changes in law or regulation occurring after the effective date. If either Party is rendered wholly or in part unable to perform its obligations under this Agreement because of an event of Force Majeure, both Parties shall be excused from whatever performance is affected by the event of Force Majeure, provided that:

(1) The non-performing Party shall, as soon as is reasonably possible after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence.

(2) The suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure.

(3) No obligations of either Party which arose before the occurrence causing the suspension of performance and which could and should have been fully performed before such occurrence shall be excused as a result of such occurrence.

ARTICLE XV: LIABILITY; DEDICATION

15.1 Limitation of Liability - Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. Neither party shall be liable to the other for any indirect, special, consequential, nor punitive damages, except as expressly authorized by this Agreement. Consequential damages will include, but not be limited to, the value of Environmental Attributes and any adverse impact to the fuel supply or the fuel supply due to the inability of Idaho Power to accept energy from the Facility.

15.2 Dedication - No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the Party or the public or affect the status of Idaho Power as an independent public utility corporation or Seller as an independent individual or entity.

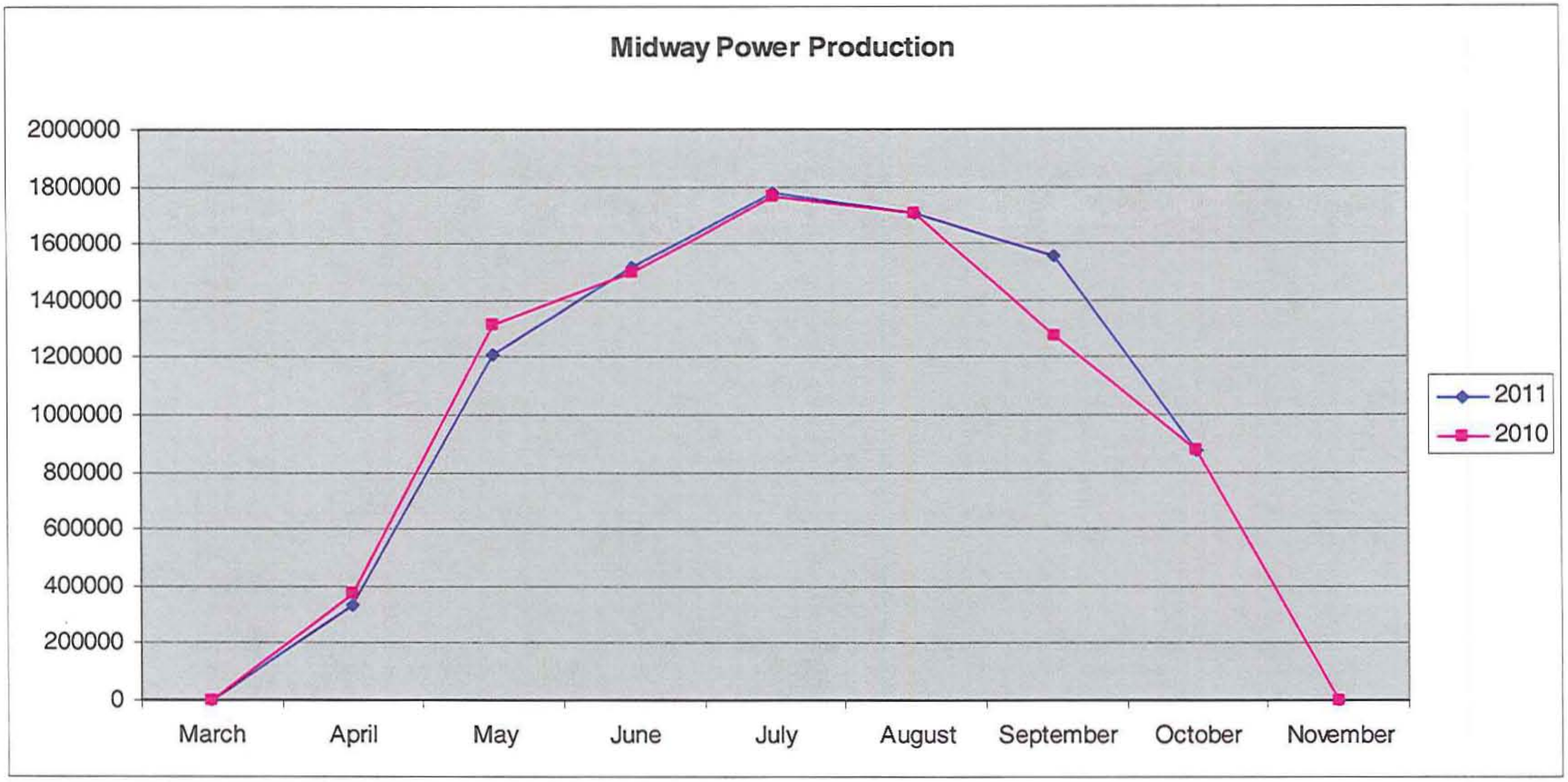

EXHIBIT 1102

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO IMPLEMENT POWER COST ADJUSTMENT (PCA) RATES FOR ELECTRIC SERVICE FROM JUNE 1, 2012 THROUGH MAY 31, 2013.	)	**CASE NO. IPC-E-12-17** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of Record, Donald L. Howell II, Deputy Attorney General, and submits the following comments in response to Order No. 32533 issued on April 25, 2012.

BACKGROUND

Idaho Power Company filed its annual power cost adjustment (PCA) Application on April 13, 2012 for rates to be effective June 1, 2012 through May 31, 2013. The PCA is a symmetrical rate adjustment mechanism that annually adjusts rates to recover a portion of above normal power supply costs from customers, or refund a portion of below normal power supply costs to customers. Idaho Power calculates the total PCA revenue increase in this case to be approximately $43.0 million which would result in an average rate increase of approximately 5.1%. When the proposed PCA increase is combined with the $27.1 million rate credits from the Company's Revenue Sharing case (Case No. IPC-E-12-13), the Company calculates an overall average rate increase for tariff customers (i.e., non-special contract customers) of 1.71%. The net rates are shown in the PCA Schedule No. 55. The annual PCA rate is combined with the Company's "base rates" to produce a customer's overall billing rate.

IDAHO POWER COMPANY'S FILING

PCA Mechanism

The annual PCA mechanism is comprised of three components: 1) a "forecast" that estimates the difference between normal power supply costs embedded in base rates and the coming year's power supply costs; 2) a "true-up" that captures the difference between the previous year's projection and actual power supply costs; and 3) a "reconciliation" of the previous year's true-up to capture the unrecovered or under-refunded amount. Each component is described in more detail below.

1. <u>The Forecast.</u> Forecasted power supply costs for the coming year are based on the Company's most recent Operating Plan and measures the difference between forecasted and normal power supply costs. The power supply cost difference is converted to a cents per kilowatt-hour (¢/kWh) rate by dividing the power costs by projected jurisdictional energy sales. In this PCA case, the Company calculates above normal power supply costs of $70.3 million relative to power supply costs contained in current base rates. After the 95/5 sharing, this produces PCA rates to recover the forecasted above normal power supply costs in the amount of 0.5099 ¢/kWh.

2. <u>The True-up.</u> The true-up amount is the difference between normal and actual power supply costs during the previous year. The previous year's PCA amount is not precisely recovered due to actual power supply costs being different than forecasted power supply costs. The true-up amount is also converted to a ¢/kWh rate by dividing by projected jurisdictional energy sales of 13,172,433 mWh. Idaho Power calculates the true-up amount and rate to be a credit to ratepayers of $17,646,658 and a credit to customers of 0.1340 ¢/kWh, respectively.

3. <u>The Reconciliation.</u> The reconciliation of the true-up tracks the recovery of the previous year's true-up amounts. It nets the actual revenue collected from the true-up rates against the amounts set for recovery. Any difference is carried into the following year's true-up reconciliation along with the true-up difference. Idaho Power calculates the reconciliation of the true-up amount and rate to be a credit to ratepayers of $5,165,169 and 0.0392 ¢/kWh, respectively.

In summary, this year the PCA rate for each class is the combination of the three PCA rate components discussed above, and a Revenue Sharing rate (discussed below). The Company calculates the combination of the three PCA components produces a 2012/2013 PCA rate surcharge of 0.3367 ¢/kWh (0.5099 - 0.1340 - 0.0392).

Revenue Sharing

The Idaho Power Revenue Sharing case (Case No. IPC-E-12-13) is being processed concurrently with this PCA case. In the Revenue Sharing case the Company proposes to credit $27.1 million to Idaho customers. The Company proposes that the Revenue Sharing credit be used to offset the proposed PCA increase. Idaho Power proposes that the Revenue Sharing credit be spread to customer classes on a uniform percent of base revenue basis and applied to reduced energy rates. These energy credits differ for each customer class. This results in a different PCA/Revenue Sharing energy rate for each customer class. These proposed rates are shown on Company Exhibit No. 2. For the four special contract customers, Idaho Power proposes that they each receive a different, flat-monthly credit during the PCA year. The proposed credits are: Micron - $46,803/mo.; Simplot - $18,362/mo.; DOE - $22,906/mo.; and Hoku - $7,685/mo. Atach 2, p.3. These rates are included in Tariff Schedule No. 55 which would be effective June 1, 2012 and would remain in effect for one year.

STAFF AUDIT AND ANALYSIS

A. The PCA Forecast or Projection

The Operating Plan used to forecast power supply costs is based on the most current information available to the Company. It takes many factors into consideration such as water conditions, gas hedges, market purchases, transmission availability, the cost of PURPA contracts, etc. Throughout the year, the Risk Management Committee (RMC) comprised of key Idaho Power employees reviews and updates the Company's risk management strategy. An account by account breakdown of the Company's power supply expense forecast is shown on Attachment A to these comments. The chart shows expenses included in Base Rates, Forecasted Expenses and the Difference. Account 555 – PURPA Purchase Expense, is shown separately from other Account 555 Non-PURPA Expenses because differences in PURPA Contract Expenses are not shared. The entire difference in PURPA QF contracts is passed on to customers.

Attachment B shows Staff's calculation of the PCA rate components. Lines 1 through 18 show the calculation of the Forecast Rate. The forecast rate is the sum of three rate elements. The first element is composed of all PCA amounts subject to 95/5 sharing. Lines 2 through 8 show this calculation. Line 8 shows the first component of the forecast rate to be 0.0005 ¢/kWh.

Lines 10 through 12 show the calculation of the second element of the forecast rate component. The second element includes all amounts, except Demand Response Incentive amounts, that are passed through to customers without sharing. These amounts are almost entirely PURPA QF contract costs. This second rate element is 0.4830 ¢/kWh as shown on line 12. This is by far the largest part of this year's PCA rate increase.

The third forecast rate element is new this year. It is Demand Response Incentives and the calculations are shown on lines 14 through 16. Commission Order No. 32426 allows Idaho Power to capture the difference between base and actual Demand Response Payments in the PCA. This third PCA forecast element is shown on line 16 to be 0.0264 ¢/kWh. These three elements combine to produce the PCA forecast rate component of 0.5099¢/kWh shown on line 18. This rate is almost entirely composed of expected increases in PURPA contract expenses. The Staff agrees with the Company's forecast calculations.

B. The PCA True-Up

The PCA true-up difference is netted against the amount collected from the application of the previous year's true up rates. This difference represents the PCA true-up deferral balance. This deferral balance is divided by expected kWh jurisdictional sales to provide the true-up rate component.

Page 1, lines 4 through 90 of Company Exhibit No. 1 calculates a true-up deferral amount – a credit of $17,646,658. Attachment C contains Staff's verification of the Company's true-up deferral calculations. Staff finds the Company's calculation as shown in Exhibit No. 1 to be correct.

To verify revenues and costs associated with Idaho Power's true-up deferrals, Staff conducted an audit of actual revenues and expenses that occurred during the PCA year (April 1, 2011 through March 30, 2012). These revenues and costs included water lease expenses, fuel expenses for coal, fuel expenses for natural gas, power sales and purchases, third-party transmission expenses, Hoku First Block Energy revenues, Renewable Energy Credits

(RECs) sales, Emission Allowance sales, and Qualifying Facilities (QF) expenses. The Risk Management Operating Plans and RMC minutes were also reviewed.

The following items are included in the PCA true-up component:

1. Load Change Adjustment. This year's true-up calculation includes a negative Load Change Adjustment of $12,621,398. Actual loads during the true-up year were below normal loads in 11 of 12 months. The actual load for the PCA year was below normal by 655,506 MWh. This represents a 4.2% decline in load. The load change adjustment is the product of the negative load growth and the load change adjustment rate (LCAR) of $19.67/MWh for the months of April through December 2011, and $18.16/MWh for January through March 2012. The LCAR is composed of the energy classified fixed costs of production embedded in base rates. When load grows, the adjustment reduces power supply costs to avoid double counting production costs. When load declines, the adjustment reimburses the Company for a portion of lost fixed production costs. The result is that $12,621,398 (before Jurisdictional Allocation and PCA sharing) has been added to the deferral balance for recovery from customers in this year's PCA. This increase due to the LCAR is a cost to customers and is subject to jurisdictional allocation and sharing.

2. Water Leases. The Company sometimes leases water for the production of hydro power from several entities. The increase or decrease in the water lease expense from base rates is included in the PCA for recovery from or credit to customers. This year's PCA deferral balance includes actual water lease expenses of $2,577,915 and the amount included in base rates is $1,825,371, with the difference of $752,544 included in the deferral balance. This increase in water lease expenses from base expenses is a cost to customers and is subject to jurisdictional allocation and sharing.

3. Fuel Expense - Coal. A portion of Idaho Power's electricity comes from coal plants. The three coal plants that Idaho Power owns an interest in are the Bridger, Valmy and Boardman plants. The increase or decrease in the coal expense from base rates is included in the PCA for recovery from or credit to customers. For the audit period of April 2011 to March 2012, the total coal expense for the three plants is $122,922,864. The total coal expense included in base rates is $167,418,061. This year's PCA deferral balance includes a difference between costs currently included in rates and actual costs of $44,495,197. This decrease in coal costs from base costs is a benefit to customers and is subject to jurisdictional allocation and sharing.

4. Fuel Expense - Gas. Idaho Power currently owns and operates several gas-fired combustion turbine generating plants at the Evander Andrews Power Complex (3 Danskin units) and at Bennett Mountain. These plants are located at Mountain Home and currently account for 100% of the Company's natural gas usage.

For the audit period of April 2011 through March 2012, the total variable gas and gas transportation expense for all the gas plants was $10,877,122. The total gas and gas transportation expense included in base rates is $6,051,627. This increase in gas expense from base rates is included in the PCA. In this year's PCA deferral balance, the additional gas expense that is included for future recovery from customers is $4,825,495. This increase in natural gas expenses from base expenses is a cost to customers and is subject to jurisdictional allocation and sharing.

5. Power Sales and Purchases. Staff reviewed the power purchases and sales in conjunction with the Company's Operating Plan. Staff did not find any transaction that was not reasonable or did not follow the Risk Management Committee's recommendations. These transactions were made with an assortment of credit-worthy partners on a timely basis, and there were no transactions conducted with an Idaho Power affiliate.

a. Power Sales. During the PCA year ending March 31, 2012, the Company sold off-system surplus power totaling $96,750,895. The total surplus sales included in base rates is $92,476,391. This increase in the power sales from base rates is included in the PCA. Actual surplus sales were more than base amounts by $4,274,504. This increase in revenues is a benefit to customers and is subject to jurisdictional allocation and sharing.

b. Power Purchases. During the PCA year ending March 31, 2012, the Company made market power purchases, excluding its PURPA contracts. The total amount of power purchases is $62,156,365. The amount of power purchases included in base rates is $66,570,302. Actual power purchases were less than base amounts by $4,413,937. This decrease in costs is a benefit to customers and is subject to jurisdictional allocation and sharing.

6. Third-Party Transmission. In Order No. 30715, the Commission found that third-party transmission costs that are incurred in conjunction with market purchases and off-system sales should be tracked through the PCA like other variable power supply costs. Including transmission expenses in the PCA is a straightforward treatment of power supply costs that fluctuate with power purchases and sales.

For the audit period of April 2011 through March 2012, the actual third-party transmission expense is $6,516,274. The third-party transmission expense included in base rates is $8,247,222. This year's PCA deferral balance includes the difference between actual costs and base costs of $1,730,948. Because the actual costs are less than the amount included in base rates, this amount represents a benefit to customers. This benefit to customers is subject to jurisdictional allocation and sharing.

7. Hoku First Block Energy. In Order No. 32426 (Case No. IPC-E-11-08), the Commission determined that the first block energy revenue from Hoku is to be included in base rates like secondary sales revenue. The variation between what is built into base rates and the actual Hoku revenues are tracked in the PCA. The amount of Hoku First Block Energy revenues included in base rates is $5,773,675. The actual amount of Hoku First Block Energy revenues during the current PCA period is $14,477,351. The actual revenues are more than the amount included in base rates by $8,703,676. These additional revenues are a benefit to customers and are subject to jurisdictional allocation and sharing.

8. Emission Allowance Sales. In Order No. 32424, the Commission ordered that revenues from the sale of emission allowances, plus any applicable interest, be reflected in the PCA and benefit customers by reducing the Company's PCA deferral balance, subject to jurisdictional allocations and sharing. The amount included in the deferral balance is $25,202 and is a benefit to customers.

9. Renewable Energy Credit Sales. In Order No. 30818, the Commission ordered that revenues from the sale of renewable energy credits (RECs) benefit customers and be subject to jurisdictional allocation and sharing. The amount included in the deferral balance is $5,521,597 and is a benefit to customers.

10. Actual PURPA Purchases Including Net Metering and Raft River Expenses. A Qualifying Facility (QF) is a generating facility which meets the requirements for QF status under the Public Utility Regulatory Policies Act of 1978 (PURPA) and FERC's 18 C.F.R. Part 292, and has obtained certification of its QF status.

For the audit period of April 2011 through March 2012, the actual PURPA expense is $103,846,995. The PURPA expense included in base rates is $62,739,020. The difference between actual PURPA expense and base PURPA expense is included in the PCA for recovery from or credit to customers. In this year's PCA deferral balance, the actual PURPA expense was more than the PURPA expense included in base rates by $41,107,975. This amount is a cost to customers and increases the PCA deferral balance. PURPA contracts are not currently subject to sharing, but they are subject to jurisdictional allocation.

11. Demand Response Incentive Payments. In Order No. 32426 (Case No. IPC-E-11-08), the Commission determined that Demand Response Incentive Payments be included in base rates and that differences between base and actual expenses be tracked through the PCA. Idaho Demand Response Incentive payments are directly assigned to Idaho and are not subject to sharing. For the PCA period (April 2011 to March 2012), there were no actual Demand Response Incentive Payments. The base amount of incentive payments included in base rates during the PCA period is $2,715,842. The difference between the actual amount and the base amount is $2,715,842 and is a benefit to customers.

The Idaho customer true-up Deferral Balance is composed of the following:

Load Change Adjustment	$12,621,398
Water Leases	$752,544
Fuel Expense – Coal	$(44,495,197)
Fuel Expense – Gas	$4,825,495
Surplus Sales	$(4,274,504)
Non-Firm Purchases	$(4,413,937)
Third Party Transmission	$(1,730,948)
Hoku Energy	$(8,703,676)
Subtotal – Change from Base	$(45,418,825)
Emission Allowance Sales Credit	$(25,202)
Renewable Energy Credit Sales	$(5,521,597)
Subtotal – Subject to Jurisdictional Allocation & Sharing	$(50,965,624)
Subtotal - After Jurisdictional Allocation and Sharing	$(45,996,476)
Qualifying Facilities – After Jurisdictional Allocation	$39,052,576
Demand Response Incentive Payments	$(2,715,842)
Total all Expense Items	$(9,659,742)
Revenue from the Forecast	$(7,823,682)
Deferral Balance	$(17,483,424)
Interest on the Deferral Balance	$(163,234)
Deferral Balance (Credit)	**$(17,646,658)**

The Company-proposed true-up rate credit is 0.1340 ¢/kWh. Although Staff calculates the same rate, as shown on Staff Attachment B, line 23, Staff is concerned that the Company does not use actual energy sales to calculate revenue from the previous year's forecast rate. The Company uses normalized energy amounts. The methodology used by the Company has been in use for many years and has been accepted by the Commission as it has approved past PCA rates.

Instead of using normalized energy sales to estimate forecast revenues in determining true-up revenue, Staff believes it may be more appropriate in future PCA years for the Company to use actual energy sales and the approved forecast rate to determine true-up revenue. Staff proposes to immediately initiate discussions with the Company to resolve the issue on a prospective basis.

C. The Reconciliation of the True-Up

The reconciliation of the true-up[1] amount is the difference between what was approved to be collected or refunded when the PCA rate for last year's true-up was set and what was actually collected or refunded. The reconciliation of the true-up may benefit either the Company or customers because any true-up over-collection is returned to customers, and any true-up under-collection is recovered by the Company.

The reconciliation of the true-up included the following amounts:

2010-11 Forecast True-Up	$ 4,181,114
2010-11 True-Up of the True-Up Balance	($18,152,666)
Emission Allowance (Order No. 32250)	($ 491,989)
DSM Recovery (Order No. 32217)	$ 10,000,000
Net Amount Set for Recovery/(Refund)	($ 4,463,541)
Collection from True-Up Rates	($ 634,702)
Interest	($ 66,926)
True-Up Reconciliation (Credit)	**($ 5,165,169)**

This is the amount recommended for refund by the Company and Staff. When divided by expected sales it produces the reconciliation of the true-up rate credit 0.0392 ¢/kWh. This calculation is shown on Attachment B, line 25.

D. Revenue Sharing

Because the Company proposes to offset the proposed increase in PCA rates with Revenue Sharing credits, Staff reviewed Idaho Power's class allocation of the Revenue Sharing amount. Idaho Power allocated the credit to all customer classes on a uniform percent of revenue basis using forecasted billing determinants and associated class base revenues. Within each customer class the decrease was assigned to the energy rates. This creates a different ¢/kWh rate for each class. Staff accepts this revenue allocation and rate design.

[1] The reconciliation of the true-up is also commonly referred to as the "true-up of the true-up."

PCA AND REVENUE SHARING RATES

The uniform PCA rate surcharge of 0.3367 ¢/kWh is the sum of the three PCA components described above (0.5099 - 0.1340 - 0.0392). This new PCA surcharge rate, shown on Attachment B, line 28, replaces the 0.0629 ¢/kWh credit currently contained within Schedule 55 rates. In this case, the uniform PCA rate is combined with Revenue Sharing credits to arrive at the total PCA rate for each class. Attachment D shows these rates.

Combined PCA and Revenue Sharing Recovery

Attachment E shows the percentage increase in the Combined PCA-Revenue Sharing rates for all Idaho Power customer classes. It includes the uniform PCA increase and the Revenue Sharing decrease. The impact is measured against all billed revenue. The total Staff-recommended increase is $15.9 million which represents an average revenue increase of 1.89%. Increase or decrease percentages vary by customer class. Staff agrees with the Company's proposed combined rates in Schedule 55.

Other PCA Attachments

Staff has included two other attachments that provide summary or historical information concerning the PCA. Staff Attachment F summarizes PCA expense amounts and rate components for this case. The attachment also shows amounts allocated to other jurisdictions and amounts shared with shareholders. Attachment G is a bar graph that shows the amount of each PCA since its inception.

CUSTOMER NOTICE AND PRESS RELEASE

Idaho Power's PCA Application, filed on April 13, 2012, contained both the Customer Notice and Press Release. Staff reviewed both and determined they complied with requirements of Procedural Rule 125.01, IDAPA 31.01.01.125.01. However, the Customer Notice does not comply with requirements of Procedural Rule 125.03, IDAPA 31.01.01.125.03.

Rule 125.03 requires that the information provided in Customer Notices should be "clearly identified, easily understood, and pertain only to the proposed rate change." In the notice sent in this case, five paragraphs are devoted to discussing Public Utility Regulatory Policy Act (PURPA) costs. Although Staff recognizes that PURPA expenses are a major cost component in this year's PCA filing, Idaho Power's discussion of PURPA strays into a discussion of expected future PURPA costs and how those future costs will impact customers in another generic case. Although the case number for the instant PCA case (IPC-E-12-17) is not mentioned in the notice, the case number for the generic PURPA case (GNR-E-11-03) is given. The Customer Notice states that the Commission is accepting public comment in GNR-E-11-03, but there is no statement to that effect with respect to this PCA case.

In the first paragraph under the section labeled "How PURPA Impacts the PCA", the Company compares this year's PURPA-related power supply expenses to those same expenses in 2004. Staff believes a more appropriate comparison between PURPA expenses would be to compare the current PCA case and last year's PCA case. Rule 125.01 requires that the Customer Notice give the overall percentage change from current rates. As one customer noted in his comment, "It seems that Idaho Power is waging an all out war against PURPA projects." In Staff's opinion, the Customer Notice violates Rule 125.03 by addressing and referring to issues that are currently the subject of a different case. At a minimum, the invitation for customers to comment in a separate and distinct case is confusing and misleading.

Another issue of concern is the delay in mailing Notices to customers. Although the Application was filed with the Commission on April 13, the Customer Notice was mailed with Idaho Power's cyclical billings beginning on April 26, 2012 and ending May 24, 2012. Pursuant to the Commission's Notice of Application, customers had until May 15, 2012 to file comments regarding this case. The delay is problematic, particularly in a PCA case that typically has a much shorter timeline than that of general rate cases. More than 100,000 customers would not have received the Customer Notice in their bills until the comment deadline passed.

In response to this concern about the delayed notice, the Company notified Staff on May 4, 2012, that it would issue a "supplemental" Customer Notice in the form of a post card to most of the customers who would not have receive the original Notice in their bills before the comment deadline of May 15, 2012. The affected customers will receive the supplemental Notice via direct mail by May 17, 2012, and will also receive the original Notice in their monthly bills. Staff agrees with the Company that this will provide affected customers with "the opportunity...to submit comments in this case prior to a Commission decision", although the turn-around time for some customers will be quite short. For this reason, Staff encourages the Commission to consider late-filed comments from customers in its deliberations.

The Company indicated to Staff that there were two reasons for the delay in sending the Customer Notice in this case. First, the Company did not want to include more than one Customer Notice in bills; bills including the Notice regarding Case Nos. IPC-E-12-12, IPC-E-12-13 and IPC-E-12-14 were being mailed until April 23, 2012. Second, the Company reports that it takes ten days for the Customer Notices to be printed locally and then shipped to the billing vendor (located in California) that prints, stuffs, and mails the bills. In discussions with Staff, Idaho Power has acknowledged that the processing delay is problematic. The Company is now exploring options on how it can decrease the time it takes to provide customer notification, particularly with respect to cases with abbreviated comment periods such as this one.

Staff recommends that the Company be reminded of its obligation to provide timely notice to customers and be directed to comply with Procedural Rule 125 in future cases.

STAFF RECOMMENDATION

Staff recommends that the Commission approve the Company's Application and the combined PCA/Revenue Sharing rates filed by the Company in proposed Schedule 55.

Staff recommends that the Commission approve a total PCA rate comprised of the uniform ¢/kWh increase of 0.3367 and class-specific rates, as shown on Attachment D, to credit customers for Revenue Sharing amounts. The Staff recommends that these rates be effective June 1, 2012 through May 31, 2013.

Staff recommends that the Company be reminded of its obligation to provide timely notice to customers and be directed to comply with Procedural Rule 125 in future cases.

Respectfully submitted this 15th day of May 2012.

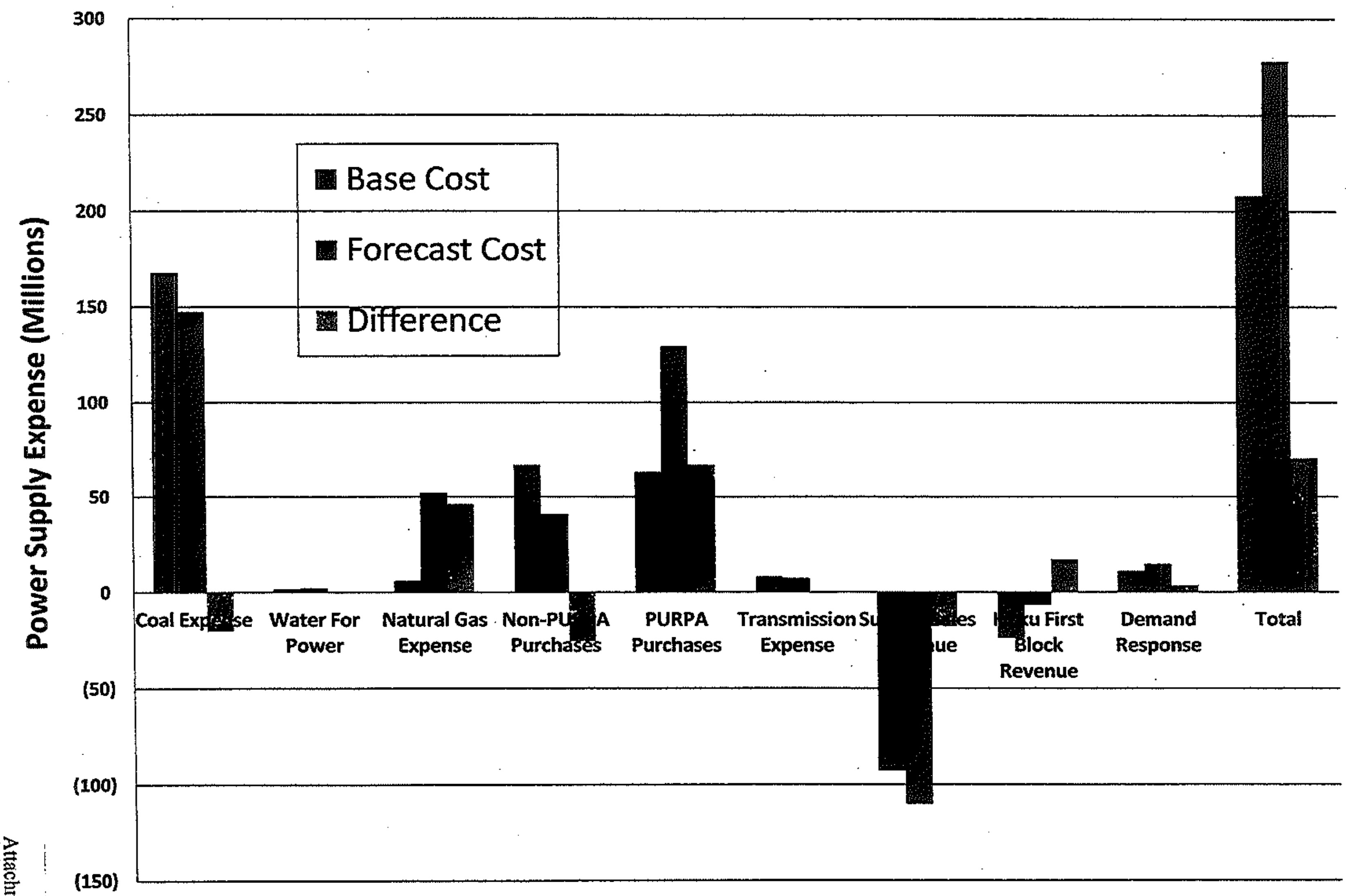
Donald L. Howell, II
Deputy Attorney General

Technical Staff: Keith Hessing
Kathy Stockton
Matt Elam
Marilyn Parker

i:umisc:comments/ipce12.17dhklskhmemp comments

POWER SUPPLY COST PROJECTION

2012 - 2013 PCA Year



Attachment A
Case No. IPC-E-12-17
Staff Comments
05/15/12

2012-2013 PCA - Twentieth Annual
IPC-E-12-17
Staff Case

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Description	Units	Base	Forecast	Difference	Rate
1	**Forecast 2012-2013:**					
2	PCA Expense (95%)	($)	133,997,217	140,832,145		
3	Hoku First Block Revenue	($)		(6,765,150)		
4	Difference	($)		134,066,995	69,778	
5	Sharing Percentage	(%)			0.95	
6	Shared Difference	($)			66,289	
7	Normalized System Firm Sales	(MWH)			13,816,139	
8	Rate for 95 % Items	(¢/kWh)			0.0005	0.0005
9						
10	PCA Expense (100%)	($)	62,851,454	129,590,113	66,738,659	
11	Normalized System Firm Sales	(MWH)			13,816,139	
12	Rate for 100% Items	(¢/kWh)			0.4830	0.4830
13						
14	Demand Response Incentives (100%)	($)	11,252,265	14,723,210	3,470,945	
15	Idaho Jurisdictional Sales	(MWH)			13,172,433	
16		(¢/kWh)			0.0264	0.0264
17						
18	Total Forecast Rate	(¢/kWh)				**0.5099**
19						
20						
21			($)	(MWh)	($/MWh)	(¢/kWh)
22						
23	**True-Up of 2011-2012:**		(17,646,658)	13,172,433	-1.340	**(0.1340)**
24						
25	**True-Up of the True-Up:**		(5,165,169)	13,172,433	-0.3921	**(0.0392)**
26						
27	**PCA Rates:**					
28	PCA Rate Adjustment From Base	(¢/kWh)				**0.3367**
29	PCA Rate Currently in Effect	(¢/kWh)				(0.0629)
30	Difference - Last Year to This Year	(¢/kWh)				0.3996
31						
32	Note: Negative rates and amounts indicate benefits to ratepayers.					
33	The True-Up calculation includes 95% sharing					

Attachment B
Case No. IPC-E-12-17
Staff Comments
05/15/12

TRUE-UP CALCULATIONS FOR 2011 - 2012
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-12-17
(Base Costs are Redistributed)

1			2011	2011	2011	2011	2011	2011	2011
2	DESCRIPTION	Units	APR	MAY	JUN	JUL	AUG	SEPT	OCT
3	**PCA Revenue**								
4	Normalized Idaho Jurisd. Sales	MWh	955,398	960,840	1,115,466	1,354,071	1,414,294	1,295,747	1,035,451
5	Forecast Rate	$/MWh	1.404	1.404	0.445	0.445	0.445	0.445	0.445
6	Revenue	$	1,341,379	1,349,019	496,391	602,562	629,361	576,607	460,776
7									
8	**Load Change Adjustment**								
9	Actual System Firm Load - Adjusted	MWh	1,011,234	1,097,667	1,300,475	1,685,331	1,585,233	1,293,353	1,040,237
10	Normalized Firm Load	MWh	1,085,384	1,282,341	1,412,842	1,685,870	1,594,331	1,225,589	1,100,776
11	Load Change	MWh	(74,160)	(184,674)	(112,367)	(539)	(9,098)	67,764	(60,539)
12	Expense Adjustment	$	1,458,531	3,632,538	2,210,259	10,602	178,958	(1,332,918)	1,190,802
13									
14	**Non-QF PCA**								
15	ACTUAL:								
16	Water Leases	$	0	(514,305)	0	0	1,464,305	1,542,915	0
17	Fuel Expense - Coal	$	6,666,551	4,771,128	5,801,423	10,194,091	13,870,557	11,740,380	11,160,165
18	Fuel Expense - Gas	$	456,072	479,664	1,392,041	1,577,118	3,177,032	485,041	491,516
19	Non-Firm Purchases	$	(264,797)	1,509,941	8,112,353	14,768,259	15,265,932	4,739,731	2,401,316
20	Third Party Transmission	$	337,992	309,423	1,054,471	898,300	860,272	519,502	883,914
21	Surplus Sales	$	(6,221,929)	(6,211,722)	(7,210,510)	(4,788,485)	(7,930,627)	(10,016,187)	(11,818,634)
22	Hoku First Block Energy	$	0	(1,638,183)	(1,692,789)	(1,178,693)	(743,176)	(2,561,825)	(1,692,789)
23	Expense Adjustment	$	1,468,531	3,632,538	2,210,259	10,602	178,958	(1,332,918)	1,190,802
24	Sub-Total	$	2,432,419	2,338,483	9,667,248	21,481,193	28,143,252	5,116,640	2,616,289
25									
26	BASE:								
27	Water for Power (Leases)	$	125,711	124,705	153,090	190,953	204,643	179,325	133,942
28	Fuel Expense - Coal	$	11,529,868	11,437,623	14,041,049	17,513,694	18,769,296	16,447,224	12,284,817
29	Fuel Expense - Gas	$	416,768	413,433	507,539	633,064	678,450	594,515	444,057
30	Non-Firm Purchases	$	4,584,612	4,547,932	5,583,131	6,963,955	7,463,219	6,539,896	4,884,602
31	Third Party Transmission	$	567,976	563,431	691,679	862,746	924,599	810,211	605,165
32	Hoku First Block Energy	$	0	0	0	0	0	0	0
33	Surplus Sales	$	(6,368,731)	(6,317,778)	(7,755,827)	(9,674,005)	(10,367,560)	(9,084,921)	(6,765,741)
34	Sub-Total	$	10,856,204	10,769,346	13,220,661	16,490,407	17,672,647	15,486,250	11,567,042
35									
36	Change From Base	$	(8,423,785)	(8,430,863)	(3,553,413)	4,990,786	8,470,605	(10,369,610)	(8,950,753)
37	Emission Allowance Sales Credit	$	0	0	0	(21,756)	0	0	0
RECS * 38	Renewable Energy Credit Sales	$	(998,372)	(307,898)	(264,172)	(623,014)	(550,822)	(410,643)	(403,702)
39	Sub-Total	$	(9,422,157)	(8,738,761)	(3,817,585)	4,346,015	7,919,782	(10,780,253)	(9,354,455)
40									
41	Deferral (Shared and Allocated)	$	(8,503,496)	(7,886,732)	(3,445,370)	3,922,279	7,147,603	(9,729,178)	(8,442,396)
42									
43	**Demand Response Incentive Pmts.**								
44	Actual	$	0	0	0	0	0	0	0
45	Base	$	0	0	0	0	0	0	0
46	Change From Base	$	0	0	0	0	0	0	0
47	Deferral	$	0	0	0	0	0	0	0
48									
49	**QF Deferral**								
50	Actual (includes Net Metering)	$	6,235,518	8,098,202	11,029,872	11,225,589	9,677,446	8,186,389	7,619,052
51	Base	$	4,320,756	4,286,188	5,261,808	6,563,163	7,033,693	6,163,509	4,603,670
52	Change From Base	$	1,914,762	3,812,014	5,768,064	4,662,426	2,643,753	2,022,880	3,015,382
53	Deferral (Allocated)	$	1,819,024	3,621,413	5,479,661	4,429,305	2,511,665	1,921,736	2,864,613
54									
55	**Total Deferral** (-6+41+47+53)	$	(8,025,851)	(5,614,338)	1,537,899	7,749,022	9,029,808	(8,384,049)	(6,038,558)
56									
57	**Principal Balances**								
58	Beginning Balance	$	0	(8,025,851)	(13,640,189)	(12,102,290)	(4,353,268)	4,676,540	(3,707,509)
59	Amount Deferred	$	(8,025,851)	(5,614,338)	1,537,899	7,749,022	9,029,808	(8,384,049)	(6,038,558)
60	Ending Balance	$	(8,025,851)	(13,640,189)	(12,102,290)	(4,353,268)	4,676,540	(3,707,509)	(9,746,067)
61									
62	**Interest Balances**								
63	Accrual thru Prior Month	$	0	(7)	1,476	3,044	3,648	(5,786)	(21,278)
64	Interest @ 1% per Year	$	0	1,483	1,569	603	(9,432)	(15,492)	(23,018)
65	Prior Month's Interest Adj.	$	(7)	0	0	0	(1)	(0)	(0)
66	Total Current Month Interest	$	(7)	1,483	1,569	603	(9,434)	(15,492)	(23,018)
67	Interest Accrued to Date	$	(7)	1,476	3,044	3,648	(5,786)	(21,278)	(44,296)
68	**Balance (True-Up & Interest)**	$	(8,025,858)	(13,638,713)	(12,099,245)	(4,349,620)	4,670,754	(3,728,787)	(9,790,363)
69									
70	**True-Up of the True-Up**								
71	True-Up Revenues (Collections)	$	1,601,969	1,526,938	978,989	(420,058)	(479,166)	(458,114)	(381,700)
72									
73	Beginning Balance	$	(18,152,666)	(5,576,831)	(7,600,815)	(8,586,138)	(8,173,235)	(7,700,880)	(7,249,183)
74	Adjustments:								
75	2009-10 PCA Transfer	$	4,181,114	0	0	0	0	0	0
76	Emission Allowance - ON 32250	$	0	(491,989)		0	0	0	0
77	Rider Funds - O.N. 32217	$	10,000,000		0	0	0	0	0
78	Sub-Total	$	(3,971,552)	(6,068,820)	(7,600,815)	(8,586,138)	(8,173,235)	(7,700,880)	(7,249,183)
79	Interest @ 1% per Year	$	(3,310)	(5,057)	(6,334)	(7,155)	(6,811)	(6,417)	(6,041)
80	Revenue Applied to Interest	$	(3,310)	(5,057)	(6,334)	(7,155)	(6,811)	(6,417)	(6,041)
81	Revenue Applied to Balance	$	1,605,278	1,531,996	985,323	(412,903)	(472,355)	(451,697)	(375,659)
82	**True-Up of the True-Up Balance**	$	(5,576,831)	(7,600,815)	(8,586,138)	(8,173,235)	(7,700,880)	(7,249,183)	(6,873,525)

Note: Negative amounts indicate benefit to ratepayers

TRUE-UP CALCULATIONS FOR 2011 - 2012
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-12-17
(Base Costs are Redistributed)

1			2011	2011	2012	2012	2012	
2	DESCRIPTION	Units	NOV	DEC	JAN	FEB	MAR	TOTALS
3	**PCA Revenue**							
4	Normalized Idaho Jurisd. Sales	MWh	956,566	1,081,014	1,177,663	1,101,149	1,004,028	13,451,707
5	Forecast Rate	$/MWh	0.445	0.445	0.445	0.445	0.445	
6	Revenue	$	425,672	481,051	524,060	490,011	446,792	7,823,682
7								
8	**Load Change Adjustment**							
9	Actual System Firm Load - Adjusted	MWh	1,124,273	1,285,108	1,248,576	1,110,751	1,080,667	14,862,905
10	Normalized Firm Load	MWh	1,130,765	1,380,118	1,346,312	1,139,208	1,134,875	15,518,411
11	Load Change	MWh	(6,492)	(95,010)	(97,736)	(28,457)	(54,208)	(655,506)
12	Expense Adjustment	$	127,698	1,868,847	1,774,886	516,779	984,417	12,621,398
13								
14	**Non-QF PCA**							
15	ACTUAL:							
16	Water Leases	$	0	0	0	0	85,000	2,577,915
17	Fuel Expense - Coal	$	12,465,839	15,168,660	12,745,738	10,750,313	7,588,020	122,922,864
18	Fuel Expense - Gas	$	432,515	868,953	443,209	512,867	561,096	10,877,122
19	Non-Firm Purchases	$	3,340,059	3,783,652	3,745,779	2,106,087	2,648,054	62,156,365
20	Third Party Transmission	$	291,183	443,772	308,159	289,909	319,378	6,516,274
21	Surplus Sales	$	(7,165,338)	(7,744,097)	(8,165,168)	(8,830,414)	(10,647,785)	(96,750,895)
22	Hoku First Block Energy	$	(1,640,458)	(1,692,789)	(545,550)	(545,550)	(545,550)	(14,477,351)
23	Expense Adjustment	$	127,698	1,868,847	1,774,886	516,779	984,417	12,621,398
24	Sub-Total	$	7,851,498	12,696,998	10,307,052	4,799,991	992,630	106,443,691
25								
26	BASE:							
27	Water for Power (Leases)	$	125,889	145,752	160,651	147,407	133,303	1,825,371
28	Fuel Expense - Coal	$	11,546,178	13,367,949	14,734,456	13,519,751	12,226,156	167,418,061
29	Fuel Expense - Gas	$	417,357	483,209	532,603	488,696	441,936	6,051,627
30	Non-Firm Purchases	$	4,591,097	5,315,486	5,858,849	5,375,847	4,861,476	66,570,302
31	Third Party Transmission	$	568,779	658,522	725,838	666,000	602,276	8,247,222
32	Hoku First Block Energy	$	0	0	(2,101,561)	(1,928,309)	(1,743,805)	(5,773,675)
33	Surplus Sales	$	(6,377,740)	(7,384,028)	(8,138,843)	(7,467,879)	(6,753,338)	(92,476,391)
34	Sub-Total	$	10,871,560	12,586,890	11,771,993	10,801,513	9,768,004	151,862,517
35								
36	Change From Base	$	(3,020,062)	110,108	(1,464,941)	(6,001,522)	(8,775,376)	(45,418,826)
37	Emission Allowance Sales Credit	$	0	0	(3,446)	0	0	(25,202)
38	Renewable Energy Credit Sales	$	(688,711)	(384,236)	(326,785)	(280,351)	(282,891)	(5,521,597)
39	Sub-Total		(3,708,773)	(274,128)	(1,795,171)	(6,281,873)	(9,058,266)	(50,965,625)
40								
41	Deferral (Shared and Allocated)	$	(3,347,167)	(247,401)	(1,620,142)	(5,669,391)	(8,175,085)	(45,996,477)
42								
43	Demand Response Incentive Pmts.							
44	Actual	$	0	0	0	0	0	0
45	Base	$	0	0	988,540	907,045	820,257	2,715,842
46	Change From Base	$	0	0	(988,540)	(907,045)	(820,257)	(2,715,842)
47	Deferral	$	0	0	(988,540)	(907,045)	(820,257)	(2,715,842)
48								
49	**QF Deferral**							
50	Actual (includes Net Metering)	$	9,540,246	7,374,112	9,614,927	8,156,684	7,088,958	103,846,995
51	Base	$	4,326,868	5,009,567	5,521,658	5,066,454	4,581,686	62,739,020
52	Change From Base	$	5,213,378	2,364,545	4,093,269	3,090,230	2,507,272	41,107,975
53	Deferral (Allocated)	$	4,952,709	2,246,318	3,888,605	2,935,718	2,381,908	39,052,576
54								
55	**Total Deferral** (-6+41+47+53)	$	1,179,870	1,517,866	765,863	(4,130,729)	(7,060,226)	(17,483,424)
56								
57	**Principal Balances**							
58	Beginning Balance	$	(9,746,067)	(8,566,198)	(7,048,332)	(6,292,469)	(10,423,198)	
59	Amount Deferred	$	1,179,870	1,517,866	755,863	(4,130,729)	(7,060,226)	(17,483,424)
60	Ending Balance	$	(8,566,198)	(7,048,332)	(6,292,469)	(10,423,198)	(17,483,424)	
61								
62	**Interest Balances**							
63	Accrual thru Prior Month	$	(44,296)	(70,608)	(97,900)	(125,294)	(147,241)	
64	Interest @ 1% per Year	$	(26,312)	(27,299)	(27,394)	(21,947)	(15,993)	(163,232)
65	Prior Month's Interest Adj.	$	0	6	0	0	0	(3)
66	Total Current Month Interest	$	(26,312)	(27,292)	(27,394)	(21,947)	(15,993)	(163,234)
67	Interest Accrued to Date	$	(70,608)	(97,900)	(125,294)	(147,241)	(163,234)	
68	**Balance (True-Up & Interest)**	$	(8,636,806)	(7,146,232)	(6,417,764)	(10,570,439)	(17,646,658)	(17,646,658)
69								
70	**True-Up of the True-Up**							
71	True-Up Revenues (Collections)	$	(330,805)	(352,881)	(363,912)	(352,417)	(334,141)	634,702
72								
73	Beginning Balance	$	(6,873,525)	(6,548,448)	(6,201,024)	(5,842,279)	(5,494,731)	(18,152,666)
74	Adjustments:							
75	2009-10 PCA Transfer	$	0	0	0	0	0	4,181,114
76	Emission Allowance - ON 32250	$	0	0	0	0	0	(491,989)
77	Rider Funds - O.N. 32217	$	0	0	0	0	0	10,000,000
78	Sub-Total	$	(6,873,525)	(6,548,448)	(6,201,024)	(5,842,279)	(5,494,731)	(4,463,541)
79	Interest @ 1% per Year	$	(5,728)	(5,457)	(5,168)	(4,869)	(4,579)	
80	Revenue Applied to Interest	$	(5,728)	(5,457)	(5,168)	(4,869)	(4,579)	(66,926)
81	Revenue Applied to Balance	$	(325,077)	(347,424)	(358,744)	(347,549)	(329,562)	701,628
82	**True-Up of the True-Up Balance**	$	(6,548,448)	(6,201,024)	(5,842,279)	(5,494,731)	(5,165,169)	(5,165,169)

Note: Negative amounts indicate benefit to ratepayers

Idaho Power Company
Calculation of PCA Rate by Class
State of Idaho
Case No. IPC-E-12-17
Staff Proposal

Line No		Rate Schedule No	(1) Current Billed Revenue	(2) Allocated Revenue Sharing Benefit	(3) Test Year Billed kWh	(4) Revenue Sharing Rate Cents per kWh	(5) Uniform PCA Rate Cents per kWh	(6) Total Combined PCA Rate Cents per kWh
1	Residential Service	1,4,5	$397,700,569	($12,600,731)	4,896,272,827	(0.2574)	0.3367	0.0793
2	Master Metered Mobile Home Park	3	$381,220	($12,062)	4,942,681	(0.2440)	0.3367	0.0927
3	Small General Service	7	$14,990,300	($474,246)	144,888,296	(0.3273)	0.3367	0.0094
4	Large General Service - Secondary	9S	$176,385,854	($5,732,224)	3,056,964,925	(0.1875)	0.3367	0.1492
5	Large General Service - Primary	9P	$20,237,805	($659,119)	420,423,939	(0.1568)	0.3367	0.1799
6	Large General Service - Transmission	9T	$130,585	($4,253)	2,712,595	(0.1568)	0.3367	0.1799
7	Dusk to Dawn Lighting	15	$1,173,934	($37,871)	6,481,376	(0.5843)	0.3367	(0.2476)
8	Large Power Service - Secondary	19S	$319,273	($10,399)	6,678,959	(0.1557)	0.3367	0.1810
9	Large Power Service - Primary	19P	$81,670,938	($2,664,599)	1,930,039,445	(0.1381)	0.3367	0.1986
10	Large Power Service - Transmission	19T	$1,670,079	($54,541)	41,905,243	(0.1302)	0.3367	0.2065
11	Agricultural Irrigation Service	24	$109,785,557	($3,563,932)	1,720,204,410	(0.2072)	0.3367	0.1295
12	Unmetered General Service	40	$1,096,245	($35,561)	15,807,753	(0.2250)	0.3367	0.1117
13	Street Lighting	41	$2,959,897	($95,628)	23,165,568	(0.4128)	0.3367	(0.0761)
14	Traffic Control Lighting	42	$142,887	($4,654)	2,981,282	(0.1561)	0.3367	0.1806
15	Total Uniform Tariffs		$808,645,142	($25,949,819)	12,273,469,299			
16	Special Contracts:							
17	Micron	26	$17,176,418	($561,642)	451,138,622	N/A	0.3367	0.3367
18	J R Simplot	29	$6,727,934	($220,347)	203,558,197	N/A	0.3367	0.3367
19	DOE	30	$8,393,976	($274,869)	244,266,665	N/A	0.3367	0.3367
20	Hoku	32	$2,835,760	($92,221)	0	N/A	0.3367	0.3367
21	Total Special Contracts		$35,134,087	($1,149,078)	898,963,484			
22	Total Idaho Jurisdiction		$843,779,229	($27,098,897)	13,172,432,783			

Attachment D
Case No. IPC-E-12-17
Staff Comments
05/15/12

Combined Effect of All Filings
Staff Proposal

Present Billed Rates to 6/1/2012 Billed Rates (PCA & Revenue Sharing)

Line No	Tariff Description	(1) Rate Sch. No.	(2) Average Number of Customers	(3) Normalized Energy (kWh)	(4) Current Billed Revenue	(5) Billed Revenue Adjustments	(6) Proposed Billed Revenue	(7) Average ¢/kWh	(8) Percent Change
1	Uniform Tariff Rates:								
2	Residential Service	1	399,329	4,896,272,827	$397,700,569	$ 2,469,997	$400,170,566	8.173	0.62%
3	Master Metered Mobile Home Park	3	23	4,942,681	$381,220	$ 3,152	$384,372	7.777	0.83%
4	Residential Service Energy Watch	4	0	0	$0	$0	$0	0	N/A
5	Residential Service Time-of-Day	5	0	0	$0	$0	$0	0	N/A
6	Small General Service	7	28,165	144,888,296	$14,990,300	$ (64,502)	$14,925,798	10.302	-0.43%
7	Large General Service	9	31,614	3,480,101,459	$196,754,244	$ 5,229,661	$201,983,905	5.804	2.66%
8	Dusk to Dawn Lighting	15	0	6,481,376	$1,173,934	$ (25,478)	$1,148,456	17.719	-2.17%
9	Large Power Service	19	116	1,978,623,647	$83,660,290	$ 4,204,442	$87,864,732	4.441	5.03%
10	Agricultural Irrigation Service	24	16,642	1,720,204,410	$109,785,557	$ 2,031,893	$111,817,450	6.500	1.85%
11	Unmetered General Service	40	2,030	15,807,753	$1,096,245	$ 14,898	$1,111,143	7.029	1.36%
12	Street Lighting	41	361	23,165,568	$2,959,897	$ (37,019)	$2,922,878	12.617	-1.25%
13	Traffic Control Lighting	42	397	2,981,282	$142,887	$ 5,599	$148,486	4.981	3.92%
14	*Total Uniform Tariffs*		478,677	12,273,469,299	$808,645,142	$ 13,832,644	$822,477,786	6.701	1.71%
15									
16	Special Contracts:								
17	Micron	26	1	451,138,622	$17,176,418	$ 1,051,179	$18,227,597	4.040	6.12%
18	J R Simplot	29	1	203,558,197	$6,727,934	$ 512,666	$7,240,600	3.557	7.62%
19	DOE	30	1	244,266,665	$8,393,976	$ 605,712	$8,999,688	3.684	7.22%
20	Hoku	32	1	0	$2,835,760	$ (92,221)	$2,743,539	0.000	-3.25%
21	*Total Special Contracts*		4	898,963,484	$35,134,087	$ 2,077,337	$37,211,424	4.139	5.91%
22									
23									
24	***Total Idaho Retail Sales***		478,681	13,172,432,783	$843,779,229	$ 15,909,980	$859,689,210	6.526	1.89%

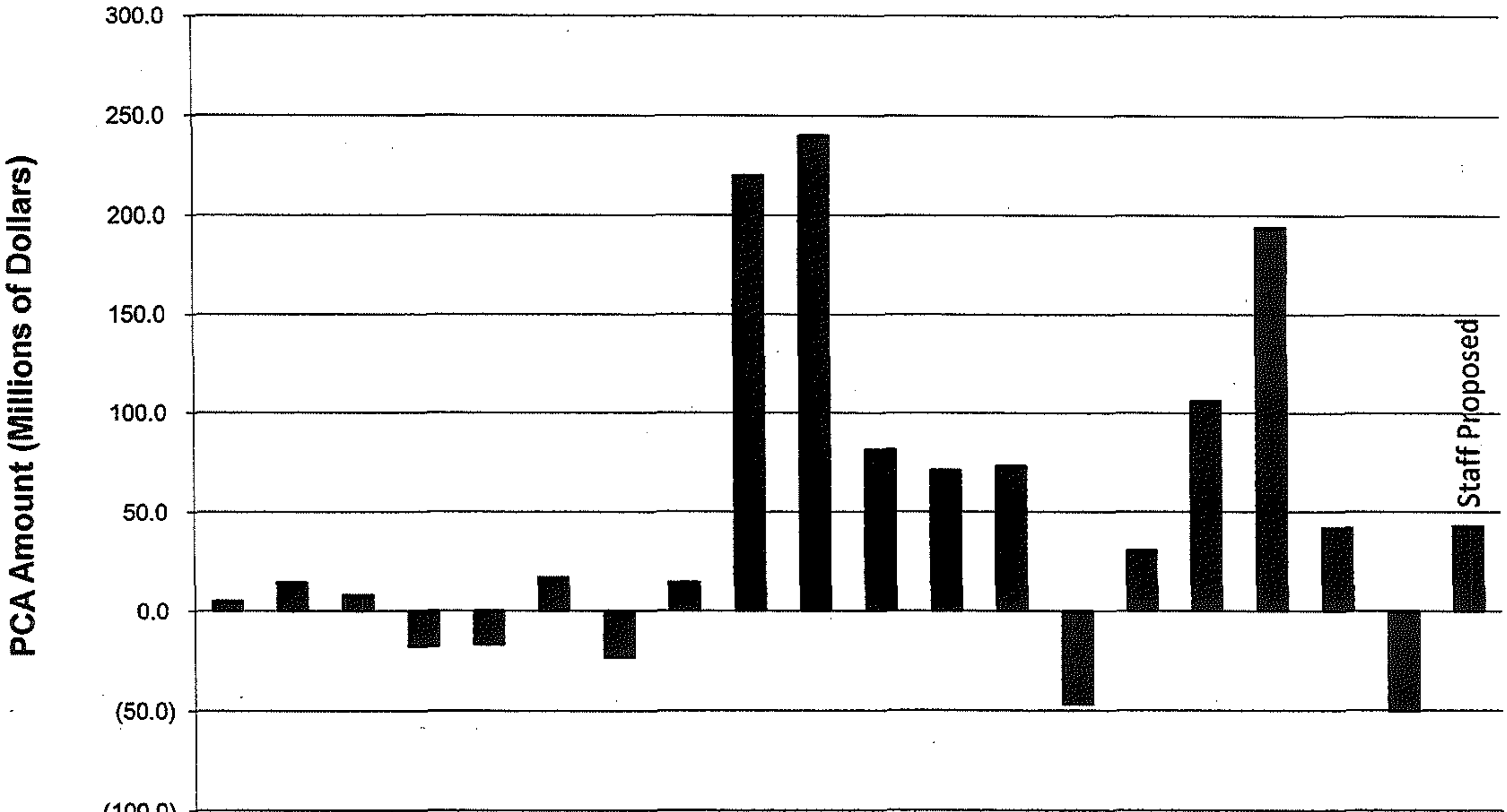
Power Supply Cost Summary
Case No. IPC-E-12-17
Base Costs are Redistributed

Description	Projection or Actual ($)	Base ($)	Difference or Initial Amount ($)	Allocated to Other Jurisdictions ($)	Shared with Shareholders ($)	Idaho Customer Revenue Requirement ($)	Idaho PCA Rates (¢/kWh)
Forecast or Projection (2012-2013)	Projection	Base	Difference				
Acct. 501 - Coal	147,503,921	167,718,084	(20,214,163)	(1,010,708)	(960,173)	(18,243,282)	
Acct. 536 - Water for Power	2,521,000	1,828,640	692,360	34,618	32,887	624,855	
Acct. 547 - Natural Gas	52,250,517	6,062,472	46,188,045	2,309,402	2,193,932	41,684,711	
Acct. 555 - Purchased Power (Non- PURPA)	41,169,588	66,689,601	(25,520,013)	(1,276,001)	(1,212,201)	(23,031,812)	
Acct. 565 - Transmission Wheeling	7,554,520	8,262,000	(707,480)	(35,374)	(33,605)	(638,501)	
Acct. 447 - Opportunity Sales Revenues	(110,167,401)	(92,642,114)	(17,525,287)	(876,264)	(832,451)	(15,816,572)	
Acct. 442 - Hoku First Block Energy Revenue	(6,765,150)	(23,921,466)	17,156,316	857,816	814,925	15,483,575	0.0005
Acct. 555 - Purchased Power (PURPA)	129,590,113	62,851,454	66,738,659	3,336,933	0	63,401,726	0.4830
Demand Response Incentive Payments	14,723,210	11,252,265	3,470,945	0	0	3,470,945	0.0264
Sub-Total	278,380,318	208,100,936	70,279,382	3,340,422	3,314	66,935,646	**0.5099**
True Up (2011-2012)	Actual	Base	Difference				
Revenue from Forecast Rate	7,823,682	0	7,823,682	0	0	7,823,682	
Load Change Adjustment	12,621,398	0	12,621,398	631,070	599,516	11,390,811	
Acct. 501 - Coal	122,922,864	167,418,061	(44,495,197)	(2,224,760)	(2,113,522)	(40,156,915)	
Acct. 536 - Water for Power	2,577,915	1,825,371	752,544	37,627	35,746	679,171	
Acct. 547 - Natural Gas	10,877,122	6,051,627	4,825,495	241,275	229,211	4,355,009	
Acct. 555 - Purchased Power (Non- PURPA)	62,156,365	66,570,302	(4,413,937)	(220,697)	(209,662)	(3,983,578)	
Acct. 565 - Transmission Wheeling	6,516,274	8,247,222	(1,730,948)	(86,547)	(82,220)	(1,562,180)	
Acct. 447 - Opportunity Sales Revenues	(96,750,895)	(92,476,391)	(4,274,504)	(213,725)	(203,039)	(3,857,740)	
Acct. 442 - Hoku First Block Energy Revenue	(14,477,351)	(5,773,675)	(8,703,676)	(435,184)	(413,425)	(7,855,068)	
Acct. 555 - Purchased Power (PURPA)	103,846,995	62,739,020	41,107,975	2,055,399	0	39,052,576	
Emission Allowance Sales Credit	(25,202)	0	(25,202)	(1,260)	(1,197)	(22,745)	
REC Sales	(5,521,597)	0	(5,521,597)	(276,080)	(262,276)	(4,983,241)	
Interest During Deferral Period	(163,234)	0	(163,234)	0	0	(163,234)	
Demand Response Incentive Payments	0	2,715,842	(2,715,842)	0	0	(2,715,842)	
Sub-Total	196,756,971	217,317,379	(20,560,408)	(492,883)	(2,420,867)	(17,646,658)	**(0.1340)**
True Up of the True Up (Reconciliation of the True Up)			Initial Amount				
Unrecovered True Up of the True Up Amount Carried Forward			(18,152,666)			(18,152,666)	
Other Limited Term Adjustments:							
PCA True Up Amount Transferred			4,181,114			4,181,114	
Emission Allowances - ON 32250			(491,989)			(491,989)	
DSM Rider Funds - ON 32217			10,000,000			10,000,000	
Interest During Amortization			(66,926)			(66,926)	
Revenue from True Up & True Up of the True Up Rates			(634,702)			(634,702)	
Sub-Total			(5,165,169)	0	0	(5,165,169)	**(0.0392)**
Total Power Cost Adjustment (PCA)							0.3367

Attachment F
Case No. IPC-E-12-17
Staff Comments
05/15/12

HISTORY OF PCA AMOUNTS

2012 - 2013 PCA Year



	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
■PCA Amounts	4.9	14.7	8.1	(17.6)	(16.7)	17.3	(23.2)	14.8	220.2	240.2	81.3	70.8	73.1	(46.8)	30.7	106.0	194.0	41.9	(50.4)	43.0

PCA Year

Attachment G
Case No. IPC-E-12-17
Staff Comments
05/15/12

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 15TH DAY OF MAY 2012, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-12-17, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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Jo Nelson
SECRETARY