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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY TO ESTABLISH ITS BASE LEVEL FOR NET POWER SUPPLY EXPENSES FOR 2010.	**CASE NO. IPC-E-10-01** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission (Commission), by and through its attorney of record, Scott Woodbury, Deputy Attorney General, and in response to the Notice of Application, Notice of Modified Procedure and Notice of Comment/Protest Deadline issued on January 28, 2010 in Case No. IPC-E-10-01, submits the following comments.

BACKGROUND

Idaho Power Company (Idaho Power; Company) filed an Application on January 19, 2010, with the Idaho Public Utilities Commission (Commission) requesting an Order approving an increase in the Company's base level of net power supply expense (NPSE). The base level NPSE amount would be used prospectively to set both base rates and establish the base level of net power supply expense for the Company's 2010-2011 Power Cost Adjustment (PCA) calculations.

On January 13, 2010, in Order No. 30978 issued in Case No. IPC-E-09-30, the Commission approved a Settlement Stipulation (Stipulation) which included a moratorium on rate case filings by Idaho Power and certain other ratemaking provisions. The Stipulation included a provision which addresses setting the base level for net power supply expenses. Paragraph 7.1 of the Stipulation reads as follows:

> 7.1. Setting the Base Level for Net Power Supply Expense. Prior to implementing the June 1, 2010, PCA and effective with the coincident PCA rate change, the Company will file with the Commission a request to change the base level for net power supply expenses to be used prospectively for both base rates and PCA calculations. The Parties will thereafter make a good-faith effort to reach agreement on the maximum change of the base level for net power supply expenses and submit any agreement to the Commission for approval.

The Company's Application and requested change in this case is filed in compliance with Section 7.1 of the Stipulation. A settlement conference of the parties was held on March 2, 2010. No agreement was reached.

Proposed Increase in Base Net Power Supply Expense

As reflected in the Company's Application, net power supply expense includes a number of categories of variable power supply expenses. Modeled variable power supply expenses include fuel expenses (FERC Accounts 501 and 547) and purchase power expenses (FERC Account 555), not including purchases from qualifying facilities (QFs) under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). To determine net power supply expense, surplus sales revenues (FERC Account 447) are deducted. In addition to the modeled variable power supply expenses categories, the base net power supply expense used for PCA computations also includes PURPA expenses (FERC Account 555), third-party transmission expense (FERC Account 565), water leasing expense (FERC Account 536), and revenue from marginal cost-based special contract pricing (FERC Account 442). The Company's base net power supply expenses are usually established in general rate cases. The last time the base net power supply expenses were reviewed and approved by the Commission was in the Company's 2008 general rate case, IPC-E-08-10. In each annual PCA, the Company's forecast of variable power supply expenses is compared to a normalized, approved variable power supply expense level and the difference is the principal driver of the PCA.

Idaho Power has computed a 2010 test year NPSE and compared it to the normalized variable power supply expenses that were approved in the Company's 2008 general rate case. Based on that comparison, the Company has calculated that the difference between the 2008 and 2010 base level NPSE on a system basis would be $78.4 million, while on an Idaho jurisdictional basis, the difference would be $74.8 million. This difference reflects the maximum adjustment to base level NPSE that would be the subject of negotiations pursuant to paragraph 7.1 of the Stipulation. Reference Application supporting testimony Exhibit 4.

STAFF ANALYSIS

Staff carefully reviewed each of the changes between Idaho Power's approved 2008 NPSE and its proposed 2010 NPSE. Attachment A shows by FERC account the approved 2008 NPSE, the proposed 2010 NPSE, and the differences between the two. The graph on page 2 of Attachment A provides a quick visual reference to indicate the relative magnitudes of each component.

The difference between Idaho Power's approved 2008 NPSE and its proposed 2010 NPSE is driven principally by increased coal costs for the Company's three coal-fired power plants, increases in the payments the Company expects to make to PURPA facilities, and reduced revenues from surplus sales due to decreased gas and electric market prices. Staff agrees with some of the proposed changes, but disagrees with others.

First, Staff agrees with the proposed increase in Account 536, Water for Power. The increase reflects the actual cost of water that will be leased from the ShoBan Tribe in 2010 at a contracted price. Staff reviewed analysis prepared by Idaho Power comparing the cost of the leased water to the value of the energy that would be generated by passing the leased water through the Company's Snake River generating plants. The analysis demonstrates that under reasonable estimates for summertime electricity prices, the benefits of the leased water substantially outweigh its cost.

Staff also agrees with the proposed increase in Account 565, Transmission. Idaho Power forecasts third party transmission expense using a combination of forward looking and historical trending approaches. Staff reviewed the Company's approaches and believes they produce a reasonable estimate of expected transmission costs.

To address the remaining accounts comprising NPSE as shown on Attachment A, Staff will discuss several issues separately below.

Increased Coal Costs

The single biggest factor causing higher net power supply costs in 2010 is increased coal costs at Bridger, Valmy and Boardman. In fact, higher coal costs account for approximately 43 percent of the proposed increase in NPSE. Coal contracts at Bridger and Valmy expired at the end of 2009, and new contracts that begin in 2010 reflect prices that are roughly 30 percent higher than in the past. A new coal supply agreement at Boardman began in 2009, and it too reflects much higher prices than before. Staff accepts the Valmy and Boardman prices, but as explained below, withholds judgment on the Bridger coal costs pending completion of further analysis.

Shortly before preparing its comments in this case, Staff became aware of issues being raised in Idaho Power's annual power cost adjustment (PCA) case in Oregon related to Bridger coal costs. The Oregon Commission Staff is alleging that a portion of the coal purchased from IERCO, an Idaho Power affiliate, that is burned as fuel for the Bridger plant is priced higher than market. In its initial testimony in the case, the Oregon Commission Staff has recommended a downward adjustment of $15,584,261 (system-wide) in Bridger coal costs. Oregon's share of the downward adjustment would be $723,110.

The Idaho Commission Staff has been conducting its own investigation into the issue. Staff is following the Oregon case, and reviewing all production requests and responses. The Oregon case is not scheduled to conclude until May 28, 2010. Staff is also posing its own production requests in Idaho, and continues to review responses from Idaho Power. Due to the compressed schedule for this case and its direct link to Idaho Power's upcoming 2010 PCA filing, Staff has been unable to complete its review of this issue. Based on the information received to date, Staff has not identified any justification for adjusting 2010 Bridger coal costs. Consequently, Staff recommends that for now, Bridger coal costs be allowed at the level proposed by Idaho Power in its Application, but that the Commission reserve the right to make adjustments to Bridger coal costs allowed in base rates in the context of Idaho Power's 2010 PCA filing. The Company's annual PCA filing is expected to be submitted on April 15, 2010, with a final order due on May 15th in order to accommodate rate changes that would be effective on June 1.

Adjustment to PURPA Costs

Increased PURPA costs represent over $23 million of the nearly $75 million proposed Idaho jurisdictional increase in NPSE. Idaho Power has signed 14 new PURPA contracts with scheduled online dates in 2010.

To determine its proposed costs for Account 555 PURPA costs, Idaho Power totaled the estimated annual payments for all of its existing PURPA contracts as well as contracts for all projects expected to come online before the end of 2010. In the past, individual PURPA contract costs have been added to base NPSE in general rate proceedings once there was a signed power sales agreement and a scheduled online date occurring before the end of the test year. Idaho Power has followed the same past practice in this case. The logic in applying this criteria was that once there was a signed power sales agreement that obligated the project to a specified online date, the costs were "known and measurable" and worthy of being included in base net power supply costs.

In this case, Staff suggests that the mere existence of a signed power sales agreement, despite its requirement of a scheduled online date, does not guarantee that a project will actually meet its scheduled online date. Staff's position is supported by the Company's recent QF contract experience with wind projects. In the Company's application, Staff identified 11 PURPA contracts that it believes will have difficulty meeting scheduled online dates in 2010. Attachment B is a list of all PURPA projects with contracts with Idaho Power that are either already online or that have scheduled online dates in 2010. Those projects that are highlighted represent proposed wind projects, all being developed by a single developer, with scheduled online dates of September 1, 2010. Collectively, these projects represent 50.2 aMW of new capacity. The original scheduled online date for each of these projects was initially May 1, 2007. However, on June 4, 2008, the scheduled online dates for these projects was changed to September 1, 2010. On January 28, 2010, Idaho Power notified Staff that the project developer now believes the operation date for all of the projects will be December 31, 2010. It remains to be seen whether the revised scheduled online dates will be met. Even if they are, there would be little or no generation recorded for 2010.

Staff believes that it is reasonable to remove the expected costs of these projects from base net power supply costs for 2010. If or when the projects do come online, Idaho Power can track those contract costs as actual expenses, which will be recoverable in annual PCA filings at 100 percent until those costs can be included in base rates in a subsequent general rate proceeding. Removal of the costs of these 11 contracts reduces Idaho Power's proposed NPSE by $7,108,922.

Due to the considerable uncertainty of PURPA projects meeting their scheduled online dates in the past, Staff proposes that in future proceedings, new PURPA contract costs only be added for recovery in base rates once they have actually achieved online dates within the test period.

Adjustment to Hoku Loads and Revenues

On March 16, 2009, the Commission issued an Order approving Idaho Power's special Energy Sales Agreement ("ESA") with Hoku Materials, Inc. ("Hoku"). *See* Order No. 30748. Under the ESA, Idaho Power was supposed to begin providing up to 43 MW of electrical service to Hoku beginning June 1, 2009, and increasing to 82 MW beginning September 16, 2009.

On May 28, 2009, Idaho Power submitted a Motion for a Commission Order authorizing a delay in the commencement of its ESA with Hoku. On June 23, 2009, Idaho Power submitted a supplemental filing seeking approval of an Amended and Restated Energy Sales Agreement implementing the changes described in the Company's prior Motion to Delay the Start Date of its ESA with Hoku and Letter Agreement. On July 24, 2009, the Commission issued an Order approving the Amended Agreement. *See* Order No. 30869. Among other things, the parties mutually agreed to the following changes to their original Agreement:

1. Delay the start date of the ESA until December 1, 2009;
2. Hoku will receive service between June 1, 2009 and November 30, 2009 as a Schedule 19T customer;
3. Hoku will limit its demand to no more than 5 MW during July 2009; 10 MW during August 2009; and no more than 25 MW for each month thereafter until November 30, 2009.

Due primarily to worldwide economic conditions and difficulties obtaining financing, Hoku has yet to complete construction of its plant and commence production. Based on available information, Staff is unable to predict or confirm that Hoku will begin taking service from Idaho Power in 2010. Because of the considerable uncertainty, Staff proposes that both the expected loads and the associated revenues attributable to Hoku be removed from Idaho Power's proposed 2010 NPSE. The effect of removing Hoku's loads and revenues is a further reduction in NPSE of $3,992,955.

Should Hoku complete its plant and begin taking service in 2010, Idaho Power would track any increase in its NPSE for recovery in its PCA at 95 percent. Revenues from first block energy sales to Hoku would also be tracked and applied as an offset to NPSE.

Other Changes in Load

Net power supply expenses also are affected by changes in the Company's loads. The Company's annual normalized system load used in its last general rate case was 15.9 million megawatt-hours (MWhs). The Company's 2010 annual normalized system load based on the 2010 test year is 15.7 million MWhs, a decrease of 200,000 MWhs. The decrease in loads from 2008, Staff believes, is consistent with the recent downturn in the economy. Notably, the load forecast used by Idaho Power for 2010 is the same forecast the Company used in the recent Langley Gulch case (IPC-E-09-03) and matches the Company's 2010 load forecast in its 2009 Integrated Resource Plan.

Non-PURPA Purchases and Surplus Sales Revenue

Under Idaho Power's proposal, a projected decrease in surplus sales revenue accounts for an increase in NPSE of nearly $24 million, almost one-third of the approximately $75 million total increase in NPSE (Idaho jurisdiction). The decrease in surplus sales revenue can be attributed to much lower electric market prices, which in turn, are caused by much lower assumed natural gas prices. In Idaho Power's 2008 general rate case, Henry Hub gas prices during the 2009 pro forma year were assumed to be $7.74 per MMBtu. In this case, the Company has assumed gas prices for 2010 to be $5.79.

Corresponding to the projected decrease in surplus sales revenue, Idaho Power's analysis also projects an increase in non-PURPA purchases. With much lower natural gas prices expected for 2010, and therefore much lower market prices, Idaho Power can purchase more energy from the market at prices lower than it would otherwise incur if it generated the power itself.

Staff reviewed Idaho Power's analysis in detail, including its Aurora (power supply model) results. Each change in Aurora input data made by Idaho Power since its 2008 rate case was identified by Staff, its effect on NPSE was estimated, and its reasonableness considered. Staff performed multiple Aurora simulations using its own assumptions. Although Staff's results differ from the Company's due to some of the issues discussed previously, Staff's results with regard to surplus sales revenue and non-PURPA purchases are very similar to Idaho Power's results. Staff believes that the gas prices used by Idaho Power in its Aurora analysis are reasonable, and agrees that surplus sales revenue is likely to decline significantly in 2010 and that costs for non-PURPA purchases will increase due to more market purchases.

Staff Proposed 2010 NPSE

Removal of the new PURPA wind contract costs and the Hoku loads and revenues discussed above affects the costs and dispatch of Idaho Power's generating plants, as well as purchases and sales as modeled in Aurora. The results from Staff's Aurora analysis are included in the NPSE account totals shown on Attachment C. Staff proposes a total NPSE for 2010 of $209,729,358. This represents an increase over 2008 authorized NPSE of $63,701,694. A summary of Staff's Aurora analysis results is shown in Attachment D for reference purposes.

STAFF RECOMMENDATIONS

Staff recommends a 2010 NPSE increase of $63,701,694. Staff further recommends that the Commission reserve the right to adjust Bridger coal costs allowed in base rates in the context of Idaho Power's 2010 PCA filing.

Respectfully submitted this 11th day of March 2010.

Scott Woodbury
Deputy Attorney General

Technical Staff: Rick Sterling

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Idaho Power
2008 Approved NPSE

Base NPSE (2008)		System	Allocation		Idaho Jurisdiction
Account 501, Coal	$	133,454,723	94.79%	$	126,498,308
Account 536, Water for Power	$	67,519	95.04%	$	64,169
Account 547, Gas	$	6,125,180	94.79%	$	5,805,901
Account 555, Non-PURPA Purchases	$	57,231,921	94.79%	$	54,248,670
Account 565, Transmission	$	10,469,726	94.79%	$	9,923,985
Account 447, Surplus Sales	$	116,568,567	94.79%	$	110,492,354
Net of 95% Accounts	$	90,780,502	94.79%	$	86,048,679
Account 555, PURPA	$	63,269,889	94.80%	$	59,978,985
Net of 100% Accounts	$	63,269,889	94.80%	$	59,978,985
Total	$	154,050,391	94.79%	$	146,027,664

Idaho Power Proposal
2010 Proposed Base Level NPSE

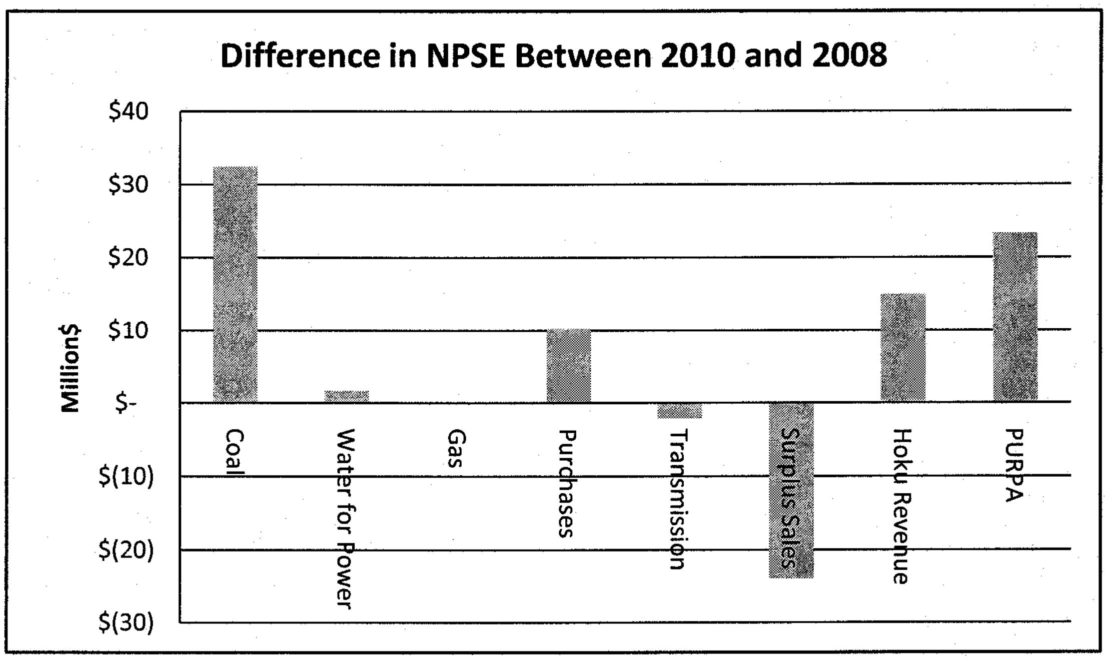
Forecast NPSE (2010)		System	Allocation		Idaho Jurisdiction
Account 501, Coal	$	167,659,463	95.00%	$	159,271,580
Account 536, Water for Power	$	1,828,640	95.22%	$	1,741,299
Account 547, Gas	$	6,052,090	95.00%	$	5,749,320
Account 555, Non-PURPA Purchases	$	67,977,200	95.00%	$	64,576,374
Account 565, Transmission	$	8,262,000	95.00%	$	7,848,661
Account 447, Surplus Sales	$	91,332,412	95.00%	$	86,763,129
Account 442, Hoku Energy Revenue	$	15,771,838	95.00%	$	14,982,786
Net of 95% Accounts	$	144,675,143	95.00%	$	137,441,319
Account 555, PURPA	$	87,781,532	95.00%	$	83,389,916
Net of 100% Accounts	$	87,781,532	95.00%	$	83,389,916
Total	$	232,456,675	95.00%	$	220,831,235
Difference	$	78,406,284	95.41%	$	74,803,571

Difference Between 2010 and 2008 Cases
2010 IPCo Proposal vs. 2008 Approved NPSE

		System	Allocation		Idaho Jurisdiction
Account 501, Coal	$	34,204,740	95.00%	$	32,493,501
Account 536, Water for Power	$	1,761,121	95.22%	$	1,677,005
Account 547, Gas	$	(73,090)	95.00%	$	(69,434)
Account 555, Non-PURPA Purchases	$	10,745,279	95.00%	$	10,207,704
Account 565, Transmission	$	(2,207,726)	95.00%	$	(2,097,276)
Account 447, Surplus Sales	$	(25,236,155)	95.00%	$	(23,973,612)
Account 442, Hoku Energy Revenue	$	15,771,838	95.00%	$	14,982,786
Net of 95% Accounts	$	53,894,641	95.00%	$	51,202,327
Account 555, PURPA	$	24,511,643	95.00%	$	23,285,352
Net of 100% Accounts	$	24,511,643	95.00%	$	23,285,352
Total	$	78,406,284	95.00%	$	74,803,571

Difference Between 2010 and 2008 Cases
2010 IPCo Proposal vs. 2008 Approved NPSE

		System	Allocation		Idaho Jurisdiction
Account 501, Coal	$	34,204,740	95.00%	$	32,493,501
Account 536, Water for Power	$	1,761,121	95.22%	$	1,677,005
Account 547, Gas	$	(73,090)	95.00%	$	(69,434)
Account 555, Non-PURPA Purchases	$	10,745,279	95.00%	$	10,207,704
Account 565, Transmission	$	(2,207,726)	95.00%	$	(2,097,276)
Account 447, Surplus Sales	$	(25,236,155)	95.00%	$	(23,973,612)
Account 442, Hoku Energy Revenue	$	15,771,838	95.00%	$	14,982,786
Net of 95% Accounts	$	53,894,641	95.00%	$	51,202,327
Account 555, PURPA	$	24,511,643	95.00%	$	23,285,352
Net of 100% Accounts	$	24,511,643	95.00%	$	23,285,352
Total	$	78,406,284	95.00%	$	74,803,571



2010 Test Year
CSPP Projects

	Total Annual Generation (kWh)	Total Annual Payment	New/Existing	Online Date
Barber Dam	12,201,512	$611,665	Existing	
Bennett Creek Wind	35,446,160	$1,933,598	Existing	
Bettencourt Dry Creek	9,756,747	$292,044	New	
Big Sky West	9,079,210	$574,963	New	
Birch Creek	279,350	$25,403	Existing	
Black Canyon #3	335,567	$23,060	Existing	
Blind Canyon	3,966,837	$344,322	Existing	
Box Canyon	1,683,941	$110,076	Existing	
Briggs Creek	3,593,060	$240,633	Existing	
Burley Butte Wind	28,629,236	$1,625,174	New	9/1/2010
Bypass	25,478,175	$1,356,053	Existing	
Canyon Springs	776,221	$24,236	Existing	
Cassia Gulch Wind Park	48,143,007	$2,799,366	Existing	
Cassia Wind Farm	28,181,837	$1,652,665	Existing	
Cedar Draw	4,905,199	$314,795	Existing	
Clear Springs Trout	3,519,410	$296,651	Existing	
CO-GEN CO	57,150,719	$3,017,652	New	
Crystal Springs	7,773,775	$511,819	Existing	
Curry Cattle Company	627,352	$44,544	Existing	
Dietrich Drop	12,989,382	$707,359	Existing	
Elk Creek	3,875,320	$265,465	Existing	
Falls River	47,706,800	$3,064,117	Existing	
Faulkner Ranch	3,141,897	$240,633	Existing	
Fisheries Development Co	952,708	$29,628	Existing	
Fossil Gulch Wind	24,303,596	$1,228,396	Existing	
Geo Bon #2	3,320,259	$245,443	Existing	
Golden Valley Wind	28,629,236	$1,625,174	New	9/1/2010
Hailey CSPP	124,112	$8,565	Existing	
Hazelton A	21,742,251	$1,110,250	Existing	
Hazelton B	21,504,060	$1,511,734	Existing	
Hidden Hollow Landfill Gas	17,720,564	$960,002	Existing	
Horseshoe Bend Hydroelectric	42,570,646	$2,912,930	Existing	
Horseshoe Bend Wind Park	19,984,333	$1,027,607	Existing	
Hot Springs Wind	46,390,007	$2,528,249	Existing	
Jim Knight	1,292,224	$91,148	Existing	
Kasel and Witherspoon	3,775,200	$289,596	Existing	
Koyle Small Hydro	3,265,848	$266,395	Existing	
Lateral # 10	7,914,528	$518,088	Existing	
Lava Beds Wind	55,409,761	$3,109,231	New	9/1/2010
Lemoyne	630,822	$43,974	Existing	
Little Wood Rvr Res	5,306,788	$389,901	Existing	
Littlewood - Arkoosh	3,304,157	$245,053	Existing	
Low Line Midway Hydro	7,730,575	$482,940	Existing	
Lowline #2	9,106,730	$484,494	Existing	
Lowline Canal	26,145,677	$1,866,652	Existing	
Magic Reservoir	19,921,481	$989,132	Existing	
Magic Valley	73,896,865	$4,777,162	Existing	
Magic West	72,048,283	$4,655,441	Existing	
Magic Wind Park	53,304,784	$3,046,379	New	9/30/2010
Malad River	1,879,896	$208,854	Existing	
Marco Ranches	2,355,073	$154,572	Existing	
Mile 28	3,945,889	$274,640	Existing	
Milner Dam Wind	51,840,683	$2,930,988	New	9/1/2010
Mitchell Butte	6,354,759	$135,423	Existing	
Mora Drop Hydro	4,767,518	$265,354	Existing	
Mud Creek S&S	1,383,628	$100,216	Existing	

2010 Test Year
CSPP Projects

	Total Annual Generation (kWh)	Total Annual Payment	New/Existing	Online Date
Mud Creek White	427,239	$28,092	Existing	
Notch Butte Wind	52,948,399	$3,027,702	New	9/1/2010
Oregon Trail Wind	28,532,196	$1,612,149	New	9/1/2010
Owyhee Dam CSPP	29,752,348	$416,514	Existing	
Pigeon Cove	7,596,697	$673,029	Existing	
Pilgrim Stage Station Wind	28,532,196	$1,612,149	New	9/1/2010
Pocatello Waste	1,435,624	$103,626	Existing	
Pristine Springs #1	872,430	$48,571	Existing	
Pristine Springs #3	1,364,706	$76,096	Existing	
Reynolds Irrigation	1,326,613	$97,560	Existing	
Rim View	1,316,640	$41,096	Existing	
Rock Creek #1	8,297,172	$787,235	Existing	
Rock Creek #2	6,644,822	$327,863	Existing	
Sagebrush	1,000,564	$70,672	Existing	
Sahko Hydro	1,040,578	$33,206	Existing	
Salmon Falls Wind	54,816,942	$3,116,833	New	9/1/2010
Schaffner	1,261,116	$93,093	Existing	
Shingle Creek	807,529	$55,869	Existing	
Shoshone #2	2,128,474	$145,851	Existing	
Shoshone CSPP	1,832,869	$145,127	Existing	
Simplot Pocatello	68,323,059	$3,780,214	Existing	
Snake River Pottery	393,518	$26,358	Existing	
Snedigar	1,222,312	$83,974	Existing	
Tamarack CSPP	36,885,798	$2,453,204	Existing	
TASCO - Nampa	1,450,255	$42,885	Existing	
TASCO - Twin Falls	242,358	$9,348	Existing	
Thousand Springs Wind	28,532,196	$1,612,149	New	9/1/2010
Tiber Dam	29,850,100	$1,445,910	Existing	
Trout - Co	854,563	$59,242	Existing	
Tuana Gulch Wind	28,532,196	$1,612,149	New	9/1/2010
Tunnel #1	17,036,939	$1,766,185	Existing	
Vaagen Brothers Lumber Inc	20,882,800	$2,018,725	Existing	
White Water Ranch	627,840	$42,316	Existing	
Wilson Lake Hydro	24,518,355	$1,726,634	Existing	
Total (kWh)	1,483,351,098	$87,781,532		
Total (aMW)	169.3			
New wind projects (kWh)	439,707,825	$24,930,078		
New wind projects (aMW)	50.2			

Wind Capacity in AURORA (aMW)	119.1

Idaho Power
2008 Approved NPSE

Base NPSE (2008)		System	Allocation		Idaho Jurisdiction
Account 501, Coal	$	133,454,723	94.79%	$	126,498,308
Account 536, Water for Power	$	67,519	95.04%	$	64,169
Account 547, Gas	$	6,125,180	94.79%	$	5,805,901
Account 555, Non-PURPA Purchases	$	57,231,921	94.79%	$	54,248,670
Account 565, Transmission	$	10,469,726	94.79%	$	9,923,985
Account 447, Surplus Sales	$	116,568,567	94.79%	$	110,492,354
Net of 95% Accounts	$	90,780,502	94.79%	$	86,048,679
Account 555, PURPA	$	63,269,889	94.80%	$	59,978,985
Net of 100% Accounts	$	63,269,889	94.80%	$	59,978,985
Total	$	154,050,391	94.79%	$	146,027,664

Staff Proposal for 2010 NPSE
Removed New PURPA Wind
Removed Hoku

Forecast NPSE (2010)		System	Allocation		Idaho Jurisdiction
Account 501, Coal	$	167,718,084	95.00%	$	159,327,268
Account 536, Water for Power	$	1,828,640	95.22%	$	1,741,299
Account 547, Gas	$	6,062,472	95.00%	$	5,759,183
Account 555, Non-PURPA Purchases	$	66,689,601	95.00%	$	63,353,192
Account 565, Transmission	$	8,262,000	95.00%	$	7,848,661
Account 447, Surplus Sales	$	92,642,114	95.00%	$	88,007,308
Account 442, Hoku Energy Revenue	$	-	95.00%	$	-
Net of 95% Accounts	$	157,918,683	95.00%	$	150,022,295
Account 555, PURPA	$	62,851,454	95.00%	$	59,707,063
Net of 100% Accounts	$	62,851,454	95.00%	$	59,707,063
Total	$	220,770,137	95.00%	$	209,729,358
Difference	$	66,719,746	95.48%	$	63,701,694

Attachment C
Case No. IPC-E-10-01
Staff Comments
03/11/10

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IPCO POWER SUPPLY COSTS FOR 2010 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS

AVERAGE

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	779,739.1	849,131.2	863,751.2	876,347.8	998,326.7	900,259.4	638,249.5	533,408.2	543,119.3	538,671.0	466,902.2	674,518.4	8,662,423.8
Bridger													
Energy (MWh)	440,384.7	398,205.0	416,287.1	311,710.9	313,083.2	360,609.4	469,059.5	472,113.2	442,743.1	466,497.8	458,307.5	473,341.8	5,022,343.2
Cost ($ x 1000)	$ 9,391.9	$ 8,493.3	$ 8,889.6	$ 6,661.8	$ 6,705.9	$ 7,740.9	$ 9,957.8	$ 10,017.8	$ 9,416.5	$ 9,907.4	$ 9,722.7	$ 10,042.0	$ 106,947.6
Boardman													
Energy (MWh)	29,998.4	28,754.2	34,111.6	30,762.6	821.9	24,552.1	36,750.8	37,300.0	35,889.0	37,765.0	36,721.6	37,482.3	370,909.6
Cost ($ x 1000)	$ 554.3	$ 526.6	$ 617.9	$ 563.1	$ 15.2	$ 458.3	$ 658.8	$ 667.4	$ 642.7	$ 674.6	$ 655.5	$ 670.2	$ 6,704.6
Valmy													
Energy (MWh)	154,212.6	141,411.2	153,150.6	94,183.4	74,096.6	136,829.0	168,983.0	171,397.3	163,029.9	171,190.3	172,025.0	175,839.3	1,776,348.2
Cost ($ x 1000)	$ 4,712.5	$ 4,318.4	$ 4,683.2	$ 2,882.9	$ 2,273.4	$ 4,194.5	$ 5,130.4	$ 5,198.3	$ 4,951.6	$ 5,193.1	$ 5,204.0	$ 5,323.5	$ 54,065.9
Danskin													
Energy (MWh)	0.3	0.3	0.3	1.3	-	1.1	14,699.4	14,758.7	141.4	406.3	196.6	185.8	30,391.5
Cost ($ x 1000)	$ 0.0	$ 0.0	$ 0.0	$ 0.1	$ -	$ 0.1	$ 801.0	$ 821.7	$ 7.9	$ 23.2	$ 14.5	$ 14.5	$ 1,682.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 314.2	$ 286.3	$ 314.2	$ 304.9	$ 314.2	$ 304.9	$ 314.2	$ 314.2	$ 304.9	$ 314.2	$ 304.9	$ 314.2	$ 3,705.8
Total Cost	$ 314.3	$ 286.3	$ 314.3	$ 305.0	$ 314.2	$ 305.0	$ 1,115.2	$ 1,136.0	$ 312.8	$ 337.4	$ 319.4	$ 328.7	$ 5,388.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	4,651.7	7,380.4	25.7	57.2	27.4	18.6	12,160.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 254.7	$ 410.9	$ 1.4	$ 3.3	$ 2.0	$ 1.5	$ 673.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 254.7	$ 410.9	$ 1.4	$ 3.3	$ 2.0	$ 1.5	$ 673.8
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	27,893.4	3,689.2	1,357.6	2,028.1	22,130.7	49,770.7	211,832.5	211,811.0	61,730.4	3,252.9	21,169.1	44,547.2	661,212.8
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	57,947.5	26,882.3	27,073.4	29,114.2	52,937.3	113,689.8	279,468.8	273,088.5	83,740.4	34,437.1	50,912.1	81,464.5	1,110,756.0
Market Cost ($ x 1000)	$ 830.7	$ 106.8	$ 31.9	$ 59.4	$ 882.7	$ 1,690.9	$ 14,075.5	$ 11,933.6	$ 3,026.1	$ 167.5	$ 1,376.6	$ 2,904.0	$ 37,085.7
Contract Cost ($ x 1000)	$ 1,593.0	$ 1,234.1	$ 1,008.9	$ 1,062.9	$ 1,207.5	$ 4,701.6	$ 5,295.0	$ 4,862.4	$ 1,180.4	$ 1,663.1	$ 1,904.4	$ 2,357.5	$ 28,070.9
Total Cost Excl. CSPP ($ x 1000)	$ 2,423.7	$ 1,341.0	$ 1,040.8	$ 1,122.4	$ 2,090.2	$ 6,392.5	$ 19,370.4	$ 16,796.1	$ 4,206.5	$ 1,830.5	$ 3,281.0	$ 5,261.6	$ 65,156.6
Surplus Sales													
Energy (MWh)	224,403.7	387,471.8	465,565.9	396,005.7	313,644.7	245,711.8	33,385.8	21,371.2	136,446.3	244,098.6	136,308.6	151,232.6	2,755,646.4
Revenue Including Transmission Costs ($ x 1000)	$ 7,878.1	$ 13,437.5	$ 15,872.4	$ 12,502.7	$ 8,903.9	$ 6,863.2	$ 1,171.9	$ 725.1	$ 4,688.2	$ 9,617.4	$ 6,188.1	$ 7,549.3	$ 95,397.8
Transmission Costs ($ x 1000)	$ 224.4	$ 387.5	$ 465.6	$ 396.0	$ 313.6	$ 245.7	$ 33.4	$ 21.4	$ 136.4	$ 244.1	$ 136.3	$ 151.2	$ 2,755.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 7,653.7	$ 13,050.1	$ 15,406.8	$ 12,106.6	$ 8,590.3	$ 6,617.5	$ 1,138.5	$ 703.7	$ 4,551.8	$ 9,373.3	$ 6,051.8	$ 7,398.0	$ 92,642.1
Hoku First Block Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Power Supply Costs ($ x 1000)	$ 9,743.0	$ 1,915.6	$ 139.0	$ (571.4)	$ 2,808.6	$ 12,473.7	$ 35,348.9	$ 33,522.7	$ 14,979.8	$ 8,573.0	$ 13,132.8	$ 14,229.4	$ 146,295.0
Total Energy (MWh)	1,237,878.8	1,056,912.3	1,028,808.2	946,114.5	1,125,621.0	1,290,229.2	1,578,477.1	1,488,075.1	1,132,242.5	1,004,926.0	1,048,783.8	1,291,618.2	14,229,686.8

Thermal Generation (MWh) (Br, Bo, V)	7,169,601
Hydro Generation (MWh)	8,662,424
Combustion Turbine (MWh)	42,552
Total Market Purchases (MWh)	661,213
Total Market Sales (MWh)	2,755,646
Total Thermal Unit Fuel Costs ($000)	170,075
Total Market Purchases ($000)	37,086
Total Market Sales ($000)	95,398
Net Power Supply Costs ($000)	111,763

Jim Bridger	5,022,343
Valmy	1,776,348
Boardman	370,910
Danskin	30,391
Bennett Mt	12,161
2003 Normalized Cost ($000)	
Jim Bridger	106,948
Valmy	54,066
Boardman	6,705
Danskin	1,683
Bennett Mt	674

Coal	$ 167,718.084			
Gas	$ 6,062.472			
Purchased Power	$ 65,156.589	$ 1,533.012	trans losses	$ 66,689.601
Surplus Sales	$ 92,642.114			

Attachment D
Case No. IPC-E-10-01
Staff Comments
03/11/10

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 11TH DAY OF MARCH 2010, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-10-01, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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SECRETARY