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March 20, 2009

VIA ELECTRONIC FILING

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: UE 203 - In The Matter of IDAHO POWER COMPANY 2008 Annual Power Cost Update, October Update

Attention Filing Center:

Enclosed for filing in the captioned docket are an original and 5 copies of Idaho Power Company's Direct Testimony of Scott Wright. A copy of this filing has been served on all parties to this proceeding as indicated on the attached service list.

Please contact me with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Legal Assistant

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in UE 203 on the following named person(s) on the date indicated below by email and first-class mail addressed to said person(s) at his or her last-known address(es) indicated below.

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DATED: March 20, 2009

Wendy McIndoo

Wendy McIndoo
Legal Assistant

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

Idaho Power/400
Witness: Scott L. Wright

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 203

IN THE MATTER OF THE APPLICATION)
OF IDAHO POWER COMPANY FOR)
AUTHORITY TO IMPLEMENT A POWER)
COST ADJUSTMENT TARIFF SCHEDULE)
FOR ELECTRIC SERVICE TO CUSTOMERS)
IN THE STATE OF OREGON.)
)
MARCH FORECAST)
)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

SCOTT L. WRIGHT

Q. Are you the same Scott L. Wright who previously submitted testimony in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Company's March Forecast for the 2009 Annual Power Cost Update (APCU), which is required as detailed in Order No. 08-238.

Q. What is the March Forecast?

A. The March Forecast is the Company's estimate of the "expected" net power supply expense for an upcoming water year using the AURORA model. In this case, the water year is April 2009 through March 2010.

Q. Please describe the variables that are to be updated in the AURORA model for the March Forecast as delineated in Order No. 08-238.

A. The following variables are delineated in Order No. 08-238 to be updated in the March Forecast:

a. Fuel prices and transportation costs;

b. Wheeling expenses;

c. Planned outages and forced outage rates;

d. Heat rates;

e. Forecast of normalized sales and loads, updated only for known significant changes since the October APCU filing.

f. Forecast Hydro generation from stream flow conditions using the most recent water supply forecast from the Northwest River Forecast Center in Portland, Oregon, and current reservoir levels;

g. Contracts for wholesale power and power purchases and sales;

h. Forward price curve as defined below;

i. PURPA contract expenses; and

j. The Oregon state allocation factor.

Q. Which of the above variables were updated for the March Forecast?

A. All of the above variables were reviewed for the March Forecast; however, for the April 2009 through March 2010 test period the only variables that have changed from the October APCU are: (1) the forecast of normalized sales and loads; (2) the forecast of hydro conditions from the Northwest River Forecast Center; (3) known power purchases and surplus sales resulting from the Company's Risk Management Policy; and (4) the forward price curve in accordance with Order No. 08-238.

Q. Please explain why the Sales and Load Forecast was updated for the March Forecast.

A. The Sales and Load Forecast was updated to reflect new load projections based on current adverse economic conditions. The estimate of the expected net power supply expense included in the October Update included loads totaling 14,967,426 MWh, while the March Forecast reflects 14,863,016 MWh of load, a reduction of 104,410 MWh.

Q. Was the expected Hoku load included in the Sales and Load Forecast used for both the October Update and the March Forecast?

A. Yes

Q. Have the current economic conditions altered Hoku's plans?

A. No. We are in regular communication with Hoku. Just this week they confirmed their intent to continue construction of their plant and their expectation that they will commence start up and testing in early summer 2009.

Q. What water supply forecast from the Northwest River Forecast Center was used to create the hydro generation forecast for the March Forecast?

A. The forecasted monthly hydro generation levels included in the March

Forecast reflect the Northwest River Forecast Center's March 6, 2009 Final Forecast and current reservoir levels of monthly hydro generation. The March 6th Final Forecast has expected inflows into Brownlee Reservoir for April through July to be 3.35 million acre-feet (MAF), or 53% of the average level of 6.31 MAF.

Q. How does the March 6, 2009 Northwest River Forecast Center's forecast compare to last year's March 7, 2008 Northwest River Forecast Center's forecast?

A. While last year's forecast was for below average streamflows, this year's forecast is for even worse hydro conditions. The forecast for this year is significantly lower than last year's forecast by 2.15 MAF (5.5 MAF – 3.35 MAF = 2.15 MAF).

Q. Please explain how a lower than average forecast from the Northwest River Forecast Center impacts the Company's Net Power Supply Expense.

A. Lower than average stream flows result in below average hydro generation. In this case a reduction of 592,166 MWh (8,112,477 MWh – 7,520,311 MWh = 592,166 MWh) in hydro generation as compared to last year's March Forecast. Furthermore, this decrease in generation results in increased purchased power costs and decreased surplus sales revenue, leading to an increased net power supply expense.

Q. What forward price curve did the Company use to price purchased power and surplus sales?

A. Exhibit No. 401 shows the March 10, 2009 mid-Columbia price curve for the April 2009 through March 2010 test period the Company used pursuant to Order No. 08-238.

Q. What is the Company's March Forecast of net power supply expense as a result of updating loads to reflect current economic conditions, updating

water conditions to reflect the most current Northwest River Forecast, including known purchases and sales, and using the most current forward price curves as per Order No. 08-238?

A. Exhibit No. 402 shows the results of a single water condition for the April 2010 through March 2011 test period, with an updated sales and load forecast, updated stream flow conditions and reservoir levels, updated power purchases and surplus sales from the Company's Risk Management Policy (Net Hedges), and market purchased power and surplus sales repriced pursuant to Order No. 08-238. The March Forecast for net power supply expense without PURPA is $178.7 million. When you include the PURPA expense of $63.7 million, the total net power supply expense for the March Forecast is $242.4 million.

Q. What is the March Forecast unit cost per megawatt-hour ($/MWh) as determined by the Company for this filing?

A. Exhibit No. 402 shows the normalized annual sales at customer level for the April 2009 through March 2010 test period are 14,863,016 MWh. Based upon test period sales, the cost per unit for the March Forecast to become effective on June 1, 2009 is $16.31 per MWh ($242.4 million / 14.863 million MWh = $16.31 per MWh).

Q. How does this $16.31 per MWh March Forecast compare to the March Forecast that resulted from last year's computation?

A. The March Forecast for last year's April 2008 through March 2009 test period was $10.30 per MWh, as compared to this year's April 2009 through March 2010 test period of $16.31 per MWh.

Q. Please describe the calculation necessary to determine the Combined Rate which is the October APCU plus the March Forecast.

A. Exhibit No. 403 steps through the Commission specified method of calculating the Combined Rate, pursuant to Order No. 08-238. Lines 1-3 show the calculation for the October APCU rate of $10.94 per MWh. Lines 4-6 show the calculation for the March Forecast rate of $16.31 per MWh. Line 7 is calculated by subtracting the March Forecast rate from the October APCU rate multiplied by the March Forecast of Normalized Sales, line 6 minus line 3 multiplied by line 4. Line 8 is the allocated amount (95%) that is allowed for the March Forecast rate. Line 9, the Forecast Change Allowed, is calculated by multiplying line 7 by line 8. Line 10 is calculated by dividing line 9 by line 4 to create the March Forecast Rate Adjustment. Line 11 is calculated by adding line 3 with line 10 to create the Combined Rate.

Q. What rate adjustment is necessary to update the Company's current base rate to the level reflected in the Combined Rate?

A. The current base rate reflected in the net power supply expense approved by the Commission in Order No. 05-871 is $3.47 per MWh. The rate adjustment necessary to update to the Combined Rate is $12.57 per MWh ($16.04 per MWh - $3.47 per MWh = $12.57 per MWh) or 1.2570 cents per kWh.

Q. How does this year's Combined Rate compare to last year's Combined Rate?

A. The Combined Rate for last year was $10.22 per MWh, while this year's Combined Rate is $16.04 per MWh, a difference of $5.82 per MWh.

Q. Have you prepared or supervised the preparation of an exhibit showing the summary of revenue impact resulting from the Combine Rate proposed by the Company?

A. Yes. Exhibit No. 404 provides a summary of the revenue change resulting from this year's Combined Rate.

Q. What is the overall revenue impact of this year's Combined Rate compared to last year's Combined Rate?

A. The overall revenue impact of the Combined Rate is an 11.46% increase over last year's Combine Rate.

Q. Has the Company filed a tariff sheet that reflects the proposed change?

A. Yes. The Company is concurrently filing Advice No.09-04 with this filing, which contains the proposed Schedule 55, with an effective date of June 1, 2009.

Q. Does this conclude your testimony?

A. Yes it does.

IDAHO POWER COMPANY
Used to Re-Price Purchased Power and Surplus Sales for the March Forecast

Line	Mid-Columbia Forward Price Curve on:												
1	**3/10/2009**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**
2	**mcHL**	**27.00**	**22.50**	**25.25**	**38.32**	**42.27**	**37.92**	**36.32**	**41.33**	**47.60**	**48.44**	**44.98**	**40.66**
3	**mc LL**	**20.35**	**14.50**	**14.75**	**25.45**	**30.25**	**30.65**	**29.60**	**34.30**	**41.95**	**38.23**	**36.34**	**32.89**
4	**Reallocated Prices**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**
5	**HL PP**												
6	103.9%	28.05	23.38	26.23	39.81	43.91	39.40	37.74	42.94	49.45	50.33	46.73	42.24
7	**LL PP**												
8	107.1%	21.79	15.53	15.80	27.26	32.40	32.83	31.70	36.74	44.93	40.95	38.92	35.22
9	**HL SS**												
10	96.4%	26.03	21.69	24.34	36.94	40.74	36.55	35.01	39.84	45.88	46.70	43.36	39.19
11	**LL SS**												
12	93.4%	19.01	13.54	13.78	23.77	28.25	28.63	27.65	32.04	39.18	35.71	33.94	30.72

IPCO POWER SUPPLY COSTS FOR APRIL 1, 2009 -- MARCH 31, 2010 NORMALIZED LOAD OVER ONE WATER CONDITION
Repriced Using UE195 Settlement Methodology - March Forecast

	April	May	June	July	August	September	October	November	December	January	February	March	Annual
Hydroelectric Generation (MWh)	652,182.8	779,521.6	632,075.0	565,606.1	557,055.7	372,787.2	486,112.5	414,081.8	594,544.6	659,531.2	913,200.4	893,612.4	7,520,311.2
Bridger													
Energy (MWh)	330,372.1	330,372.1	433,154.5	455,179.3	455,179.3	440,496.2	455,179.3	440,496.2	455,179.3	455,179.3	411,129.7	422,142.1	5,084,059.6
Cost ($ x 1000)	$ 5,133.8	$ 5,133.8	$ 6,731.0	$ 7,073.3	$ 7,073.3	$ 6,845.1	$ 7,073.3	$ 6,845.1	$ 7,073.3	$ 7,601.5	$ 6,865.8	$ 7,049.8	$ 80,499.2
Boardman													
Energy (MWh)	33,220.7	7,273.0	33,599.7	41,171.6	41,198.2	39,816.8	41,154.0	39,837.4	41,197.5	41,201.9	37,187.1	41,121.5	437,979.5
Cost ($ x 1000)	$ 531.3	$ 117.8	$ 550.4	$ 658.5	$ 658.8	$ 636.9	$ 658.2	$ 637.1	$ 658.8	$ 708.7	$ 639.7	$ 707.5	$ 7,163.8
Valmy													
Energy (MWh)	94,676.0	161,395.1	156,278.8	174,664.0	174,314.5	167,188.9	172,743.2	168,570.6	174,606.4	175,285.1	157,383.0	172,927.4	1,950,032.9
Cost ($ x 1000)	$ 2,304.5	$ 3,936.5	$ 3,823.9	$ 4,251.9	$ 4,243.9	$ 4,072.7	$ 4,208.0	$ 4,104.2	$ 4,250.5	$ 4,838.1	$ 4,345.6	$ 4,777.1	$ 49,156.9
Danskin													
Energy (MWh)	268.1	6.1	5.1	36,059.3	18,950.3	2,422.2	365.9	7,460.7	1,429.3	5,885.9	264.8	10.5	73,128.2
Cost ($ x 1000)	$ 20.7	$ 0.5	$ 0.4	$ 2,601.5	$ 1,387.6	$ 188.0	$ 28.1	$ 610.0	$ 119.1	$ 539.9	$ 24.1	$ 0.9	$ 5,520.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 220.8	$ 220.8	$ 241.2	$ 234.4	$ 241.2	$ 234.4	$ 241.2	$ 241.2	$ 234.4	$ 241.2	$ 234.4	$ 241.2	$ 2,826.5
Total Cost	$ 241.5	$ 221.2	$ 241.6	$ 2,835.9	$ 1,628.8	$ 422.4	$ 269.3	$ 851.2	$ 353.5	$ 781.1	$ 258.6	$ 242.1	$ 8,347.4
Bennett Mountain													
Energy (MWh)	43.1	-	-	15,472.1	7,181.2	30.6	-	806.4	217.7	482.6	37.6	-	24,271.3
Cost ($ x 1000)	$ 3.5	$ -	$ -	$ 1,166.9	$ 548.6	$ 2.5	$ -	$ 69.0	$ 19.0	$ 46.3	$ 3.6	$ -	$ 1,859.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ 3.5	$ -	$ -	$ 1,166.9	$ 548.6	$ 2.5	$ -	$ 69.0	$ 19.0	$ 46.3	$ 3.6	$ -	$ 1,859.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	18,173.8	-	80,386.2	49,835.5	109,058.2	163,352.2	5,879.7	58,701.6	73,636.3	28,984.2	-	-	588,007.7
Contract Energy (MWh)	34,356.0	31,709.3	69,427.5	72,599.6	67,511.3	30,031.7	35,463.5	32,718.0	42,172.0	34,868.2	31,284.2	35,271.0	517,412.2
Total Energy Excl. CSPP (MWh)	52,529.8	31,709.3	149,813.7	122,435.1	176,569.4	193,383.9	41,343.1	91,419.7	115,808.3	63,852.4	31,284.2	35,271.0	1,105,420.0
Market Cost ($ x 1000)	$ 489.5	$ -	$ 1,604.6	$ 1,890.1	$ 4,518.0	$ 6,181.4	$ 217.2	$ 2,427.5	$ 3,555.5	$ 1,359.9	$ -	$ -	$ 22,243.9
Contract Cost ($ x 1000)	$ 1,285.0	$ 1,190.0	$ 3,317.7	$ 3,854.4	$ 3,573.4	$ 1,534.4	$ 1,804.6	$ 2,000.7	$ 2,563.6	$ 1,786.3	$ 1,603.1	$ 1,327.6	$ 25,841.0
Total Cost Excl. CSPP ($ x 1000)	$ 1,774.5	$ 1,190.0	$ 4,922.4	$ 5,744.5	$ 8,091.5	$ 7,715.8	$ 2,021.9	$ 4,428.2	$ 6,119.2	$ 3,146.2	$ 1,603.1	$ 1,327.6	$ 48,084.9
Surplus Sales													
Energy (MWh)	70,752.1	143,494.3	37,134.4	98,247.3	48,414.7	7,418.1	107,775.1	29,837.2	4,886.8	21,174.6	398,125.3	395,563.5	1,362,823.6
Revenue Including Transmission Costs ($ x 1000)	$ 1,530.7	$ 2,551.4	$ 800.7	$ 2,730.1	$ 1,484.5	$ 212.4	$ 3,223.2	$ 997.5	$ 198.1	$ 884.9	$ 15,687.2	$ 13,965.0	$ 44,265.5
Transmission Costs ($ x 1000)	$ 70.8	$ 143.5	$ 37.1	$ 98.2	$ 48.4	$ 7.4	$ 107.8	$ 29.8	$ 4.9	$ 21.2	$ 398.1	$ 395.6	$ 1,362.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,459.9	$ 2,407.9	$ 763.6	$ 2,631.8	$ 1,436.0	$ 204.9	$ 3,115.4	$ 967.7	$ 193.2	$ 863.8	$ 15,289.1	$ 13,569.4	$ 42,902.7
Net Hedges													
Energy (MWh)	(101,200.0)	(41,600.0)	10,400.0	339,600.0	135,600.0	7,600.0	(7,800.0)	30,000.0	39,000.0	16,400.0	-	(43,200.0)	384,800.0
Cost($ X 1000)	$ (5,351.2)	$ (1,591.0)	$ 13.0	$ 18,404.2	$ 8,928.4	$ 4,509.1	$ (135.2)	$ 1,390.0	$ 1,598.5	$ 725.9	$ 7.0	$ (1,944.0)	$ 26,554.6
Net Power Supply Costs ($ x 1000)	$ 3,178.0	$ 6,600.5	$ 15,518.7	$ 37,503.2	$ 29,737.2	$ 23,999.5	$ 10,980.1	$ 17,357.2	$ 19,879.6	$ 16,984.2	$ (1,565.7)	$ (1,409.2)	**$ 178,763.5**
PURPA ($ x 1000)	$ 3,760.1	$ 3,825.6	$ 3,418.3	$ 4,221.4	$ 5,290.1	$ 7,664.0	$ 8,119.4	$ 7,927.9	$ 6,414.2	$ 4,616.4	$ 4,064.0	$ 4,337.5	$ 63,659.0
Total Net Power Supply Expense ($ x 1000)	$ 6,938.1	$ 10,426.1	$ 18,937.1	$ 41,724.6	$ 35,027.4	$ 31,663.5	$ 19,099.5	$ 25,285.1	$ 26,293.8	$ 21,600.6	$ 2,498.4	$ 2,928.3	**$ 242,422.5**
Sales at Customer Level (In 000s MWH)	1,018.892	1,053.871	1,228.848	1,440.131	1,506.526	1,401.775	1,151.041	1,094.296	1,231.681	1,331.666	1,264.012	1,140.277	14,863.016
Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
Unit Cost / MWH (for PCAM)	$6.81	$9.89	$15.41	$28.97	$23.25	$22.59	$16.59	$23.11	$21.35	$16.22	$1.98	$2.57	**$16.31**
Prices Used in Purchased Power & Surplus Sales Above:													
Heavy Load													
AURORA HL Purchases	14,929.6	-	32,070.2	42,364.7	85,519.4	124,635.2	5,107.9	43,651.9	54,653.0	18,447.0	-	-	
Purchased Power HL Price	28.05	23.38	26.23	39.81	43.91	39.40	37.74	42.94	49.45	50.33	46.73	42.24	
AURORA HL Sales	26,480.7	74,634.4	27,367.6	29,979.9	9,332.8	-	33,057.5	5,331.2	983.1	11,723.7	230,808.1	214,097.9	
Surplus Sales HL Price	26.03	21.69	24.34	36.94	40.74	36.55	35.01	39.84	45.88	46.70	43.36	39.19	
Light Load													
AURORA LL Purchases	3,244.2	-	48,316.0	7,470.8	23,538.8	38,717.0	771.8	15,049.8	18,983.3	10,537.2	-	-	
Purchased Power LL Price	21.79	15.53	15.80	27.26	32.40	32.83	31.70	36.74	44.93	40.95	38.92	35.22	
AURORA LL Sales	44,271.4	68,860.0	9,766.7	68,267.5	39,081.9	7,418.1	74,717.6	24,505.9	3,903.8	9,450.9	167,317.3	181,465.7	
Surplus Sales LL Price	19.01	13.54	13.78	23.77	28.25	28.63	27.65	32.04	39.18	35.71	33.94	30.72	

ANNUAL POWER COST UPDATE
April 2009 - March 2010

Line		
	OCTOBER APCU	
1	Forecast of Normalized Sales (MWh)	14,967,426
2	Total Net Power Supply Expense	$163,774,279
3	October APCU Rate ($/MWh)	$10.94
	MARCH FORECAST	
4	Forecast of Normalized Sales (MWh)	14,863,016
5	Total Net Power Supply Expense	$242,422,546
6	March Forecast Rate ($/MWh)	$16.31
7	Sales Adjusted Forecast Power Cost Change	$79,790,726
8	Portion of Change Allowed	95%
9	Forecast Change Allowed	$75,801,190
10	**March Forecast Rate Adjustment ($/MWh)**	$5.10
11	**Combined Rate ($/MWh)**	$16.04

Idaho Power Company
Before the Public Utilities Commission of Oregon
State of Oregon
Current and Proposed Rates
12-Months Ending March 2010

Tariff Description	(1) Rate Schedule No	(2) Average No. of Customers	(3) Normalized kWh	(4) Current Revenues Effective: 6/1/08	(5) Revenue Difference	(6) Proposed Revenues Effective: 6/1/09	(7) Percent Change	(8) Mills per kWh
Uniform Tariff Rates:								
Residential Service	1	13,447	199,225,201	$11,978,108	$1,159,491	$13,137,599	9.68%	65.9435
Small General Service	7	3,011	17,234,336	1,205,965	100,304	1,306,269	8.32%	75.7946
Large General Service	9	1,346	126,880,873	7,151,522	738,446	7,889,968	10.33%	62.1841
Dusk to Dawn Lighting	15	-	424,083	100,016	2,469	102,485	2.47%	241.6626
Large Power Service	19	8	269,786,052	10,680,873	1,570,155	12,251,028	14.70%	45.4102
Irrigation Service	24	1,525	60,554,039	3,052,018	352,424	3,404,442	11.55%	56.2216
Unmetered General Service	40	3	12,900	816	75	891	9.19%	69.0698
Municipal Street Lighting	41	13	823,084	109,778	4,790	114,568	4.36%	139.1936
Traffic Control Lighting	42	6	17,262	853	100	953	11.72%	55.2080
Total Uniform Tariffs		19,359	674,957,830	$34,279,949	$3,928,254	$38,208,203	11.46%	56.6083