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December 1, 2008

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 is Idaho Power Company's Supplemental Direct Testimony of Scott Wright and the Errata Filing consisting of pages 4 through 7 of Scott Wright's Direct Testimony and accompanying exhibits Idaho Power/101, 105, 106, and 107. The Errata Filing replaces the pages and exhibits originally filed on October 23, 2008. 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,

Amie Jamieson

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: December 1, 2008

Amie Jamieson

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 203

IN THE MATTER OF IDAHO POWER)
COMPANY'S 2008 ANNUAL POWER)
COST UPDATE)
)

IDAHO POWER COMPANY

SUPPLEMENTAL DIRECT TESTIMONY

OF

SCOTT L. WRIGHT

December 1, 2008

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

A. Yes.

Q. What is the purpose of your Supplemental Direct Testimony?

A. My Supplemental Direct Testimony presents and explains two corrections to the AURORA model run that formed basis of the October Update and my Direct Testimony filed on October 23, 2008. Together these corrections are shown on the Revised Exhibit 105, and increase the cost per unit for the October Update from $9.86 per MWh to $10.94 per MWh.

Q. Please identify the AURORA model run you are correcting.

A. The originally-filed Exhibits 101 and 105 to my Direct Testimony contain the results of an AURORA model run producing estimated power supply expenses for April 1, 2009 through March 31, 2010. Over the past several days, in researching the responses to Staff Data Requests Nos. 3 and 8, I have discovered two separate errors in the data contained in the original Exhibits 101 and 105.

Q. Please describe the errors you discovered and the corrections you have made.

A. The first error relates to the Elkhorn Wind expense in the April 2009 – March 2010 AURORA run. The run originally included the Elkhorn Wind energy, but did not include the Elkhorn Wind expense, thereby understating power supply expenses. I have corrected the run by including the Elkhorn Wind expense.

The second correction removes the Raft River Geothermal PURPA contract from the run. In early 2008, the Raft River Geothermal project was reclassified from a PURPA contract to a Purchased Power Agreement. The continued inclusion of Raft River as a PURPA contract caused Raft River Geothermal to be counted twice in the run, thereby overstating power supply expenses. This removal results in a corrected PURPA total of 124 aMW, as opposed to the 133 aMW the Company previously used in its analysis.

Q. Have you corrected your Direct Testimony and accompanying exhibits to reflect these changes?

A. Yes. Along with this Supplemental Direct Testimony I am filing Errata Testimony. The Errata Testimony replaces pages 4–7 of my Direct Testimony filed on October 23, 2008. I have highlighted the numbers that are different from the originally-filed Direct Testimony for ease of reference. The Errata Testimony also includes Exhibits Idaho Power/101, Idaho Power/105, Idaho Power/106, and Idaho Power/107. These revised exhibits replace those originally filed with my Direct Testimony on October 23, 2008.

Q. Does this conclude your Supplemental Direct Testimony?

A. Yes.

UE 203

ERRATA FILING

These pages of testimony and exhibits replace the relevant pages of the Direct Testimony of Scott Wright and accompanying exhibits filed on October 23, 2008.

normalized and account for nearly 1.1 million MWh. PURPA purchases are not included on Exhibit No. 101; however, when combined with market purchases of 1.2 million MWh, total purchases amount to 2.3 million MWh (1.1 million MWh + 1.2 million MWh = 2.3 million MWh) approximately 13 percent (2.3 million MWh / 18.5 million MWh = 13 percent) of the generation mix. Of the 18.5 million MWh consumed, 16.4 million MWh are utilized for system loads while nearly 2.1 million MWh are sold as surplus.

Q. Please describe the change in PURPA generation and expenses since last year's October filing.

A. PURPA generation decreased from 189 average megawatts (aMW) to 124 aMW, a 65 aMW reduction. PURPA expenses also decreased from $93.1 million to $63.7 million, a $29.4 million reduction. This reduction was caused by several PURPA projects, mostly wind, failing to meet their expected on-line dates.

Q. Please describe the change in the Company's system loads since last years October filing.

A. The Company's annual normalized system load used in last year's April 2008 through March 2009 filing was 1,825 aMW. The Company's April 2009 through March 2010 annual normalized system load used in this filing is 1,875 aMW, an approximate 2.7 percent increase.

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

A. For the October Update, the Company used the methodology approved in Order No. 08-238. This methodology uses a one year average of the daily forward price curves for April 2010 through March 2011 shown in Exhibit No. 102, which is then discounted for inflation back to April 2009 through March 2010 according to the quarterly inflation indices provided on Exhibit No. 103.

Q. What are the average forward price curves the Company used to re-price purchased power and surplus sales for the normalized test year?

A. Exhibit No.104 shows the revised monthly prices for April 2009 through March 2010. These are considered the "normal" forward prices used to re-price the Company's purchased power and surplus sales estimates for the normalized test year.

Q. How does the re-pricing of purchased power and surplus sales, using a "normal" forward price curve, change the purchased power expenses and surplus sales revenues as modeled by AURORA?

A. Exhibit No. 101 shows the purchased power expenses and surplus sales revenues before re-pricing. Exhibit No. 105 shows the same normalized generation dispatch, with purchased power and surplus sales re-priced using the normalized forward price curve shown in Exhibit No. 104. A comparison of Exhibit No. 101 and Exhibit No. 105 demonstrates the changes due to re-pricing. Purchased power expenses increase by $0.5 million, moving from $53.1 million to $53.6 million. Surplus sales revenues increase by $20.7 million, moving from $104.3 million to $125 million.

Q. Does the methodology used to estimate the power supply

expenses represented in Exhibit No. 104 conform with the methodology detailed in Order No. 08-238?

A. Yes, it does.

Q. What is the October Update unit cost per megawatt-hour ($/MWh) represented by this filing?

A. Exhibit No. 105 shows the normalized annual sales at customer level for the April 2009 through March 2010 test year are 14,967,426 MWh. Based upon test year sales, the cost per unit for the October Update to become effective on June 1, 2009 is $10.94 per MWh ($163.8 million / 14.967 million MWh = $10.94 per MWh).

Q. How does this $10.94 per MWh October Update compare to the October Update that resulted from last year's computation?

A. The October Update unit cost that was part of the Combined Rate which became effective June 1, 2008 was $8.70 per MWh. This year's October Update of $10.94 per MWh equates to an increase of $2.24 per MWh ($10.94 – $8.70 = $2.24).

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

A. Yes. Exhibit No. 106 provides a summary of the revenue change resulting from this year's October Update as compared to last year's October Update.

Q. What is the overall revenue impact of this year's October

Update?

A. The overall revenue impact of the October Update is a 4.55% increase.

Q. Please explain the components that make up the Adjustment Rates on Schedule 55.

A. The October Update, as described by this filing, is combined with the March Forecast Rate, to create a Combined Rate. The Adjustment Rates detailed in Schedule 55 are the difference between the Combined Rate and the Base Rate established in UE 167.

Q. What are the Adjustment Rates as a result of this October Update?

A. For purposes of this filing, the Combined Rate was calculated using the October Update of $10.94 per MWh plus the current March Forecast Rate for April 2008 through March 2009 of $1.52 per MWh. The Combined Rate equates to $12.46 per MWh ($10.94 + $1.52 = $12.46). The Adjustment Rates are the difference between the Combined Rate of $12.46 per MWh and the current Base Rate of $3.47 per MWh, established in UE 167. This difference is $8.99 per MWh ($12.46 - $3.47 = $8.99). The Adjustment Rates are 0.8990 cents per kilowatt-hour.

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

A. Yes. The Company has filed a draft Schedule 55 that reflects the October Update which will serve as a placeholder until the March Forecast for

IPCO POWER SUPPLY COSTS FOR APRIL 1, 2009 - MARCH 31, 2010 (Multiple Gas Prices/80 Hydro Conditions)

AVERAGE

	April	May	June	July	August	September	October	November	December	January	February	March	Annual
Hydroelectric Generation (MWh)	864,268.9	866,449.0	842,395.2	727,873.1	688,036.5	555,471.4	527,759.4	478,321.1	695,521.7	743,548.7	858,155.2	870,114.3	8,717,914.4
Bridger													
Energy (MWh)	330,372.1	330,372.1	429,803.8	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	5,080,708.9
Cost ($ x 1000)	$ 5,133.8	$ 5,133.8	$ 6,679.0	$ 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	$ 80,447.1
Boardman													
Energy (MWh)	30,791.4	6,410.6	28,422.9	40,365.2	41,031.4	39,532.0	40,965.7	39,726.2	41,067.7	38,748.7	34,978.2	39,163.3	421,203.3
Cost ($ x 1000)	$ 496.8	$ 105.3	$ 471.2	$ 647.2	$ 656.5	$ 632.9	$ 655.6	$ 635.6	$ 657.0	$ 671.7	$ 606.7	$ 678.0	$ 6,914.5
Valmy													
Energy (MWh)	88,830.8	157,350.2	151,362.6	172,657.9	173,151.8	166,575.0	172,391.7	168,288.3	174,160.1	167,583.7	150,037.1	166,302.1	1,908,691.2
Cost ($ x 1000)	$ 2,171.1	$ 3,844.3	$ 3,712.0	$ 4,206.1	$ 4,217.3	$ 4,058.7	$ 4,200.0	$ 4,097.8	$ 4,240.4	$ 4,639.1	$ 4,155.9	$ 4,605.9	$ 48,148.6
Danskin													
Energy (MWh)	64.4	1.0	371.4	18,418.2	9,753.4	1,199.8	613.2	4,822.8	2,289.7	1,199.1	420.0	62.6	39,215.7
Cost ($ x 1000)	$ 6.2	$ 0.1	$ 33.4	$ 1,507.8	$ 794.9	$ 111.1	$ 52.4	$ 428.3	$ 216.0	$ 132.9	$ 47.3	$ 6.6	$ 3,336.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.5	$ 296.9	$ 315.5	$ 306.2	$ 315.5	$ 306.2	$ 315.5	$ 315.5	$ 306.2	$ 315.5	$ 306.2	$ 315.5	$ 3,730.3
Total Cost	$ 321.7	$ 297.0	$ 348.9	$ 1,814.0	$ 1,110.4	$ 417.3	$ 367.9	$ 743.8	$ 522.2	$ 448.4	$ 353.5	$ 322.1	$ 7,067.1
Bennett Mountain													
Energy (MWh)	2.4	-	10.4	7,658.1	3,726.1	59.9	14.4	404.8	134.1	70.2	23.8	0.6	12,104.9
Cost ($ x 1000)	$ 0.2	$ -	$ 1.0	$ 658.1	$ 313.7	$ 5.9	$ 1.4	$ 38.0	$ 13.2	$ 8.2	$ 2.8	$ 0.1	$ 1,042.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ 0.2	$ -	$ 1.0	$ 658.1	$ 313.7	$ 5.9	$ 1.4	$ 38.0	$ 13.2	$ 8.2	$ 2.8	$ 0.1	$ 1,042.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	4,048.0	11,051.7	70,244.5	187,228.9	104,442.2	67,262.7	8,781.5	65,667.7	93,483.4	93,575.4	4,424.8	1,388.2	711,599.0
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)	38,404.0	42,761.0	139,672.0	259,828.5	171,953.5	97,294.3	44,245.0	98,385.7	135,655.4	128,443.6	35,709.0	36,659.1	1,229,011.2
Market Cost ($ x 1000)	$ 271.8	$ 707.5	$ 4,131.4	$ 13,485.3	$ 7,364.0	$ 5,534.1	$ 728.7	$ 5,524.1	$ 7,474.4	$ 7,403.7	$ 403.3	$ 98.3	$ 53,126.6
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)	$ 1,556.7	$ 1,897.5	$ 7,449.2	$ 17,339.7	$ 10,937.4	$ 7,068.5	$ 2,533.3	$ 7,524.9	$ 10,038.0	$ 9,190.0	$ 2,006.4	$ 1,425.9	$ 78,967.6
Surplus Sales													
Energy (MWh)	355,681.0	271,256.5	206,160.4	20,049.8	14,772.6	75,161.1	150,111.6	56,220.7	72,282.3	123,788.2	326,344.6	396,926.6	2,068,755.4
Revenue Including Transmission Costs ($ x 1000)	$ 17,359.1	$ 11,482.0	$ 6,897.2	$ 993.0	$ 847.9	$ 3,836.0	$ 7,712.4	$ 2,810.0	$ 4,065.8	$ 6,404.9	$ 18,933.3	$ 22,992.2	$ 104,333.7
Transmission Costs ($ x 1000)	$ 355.7	$ 271.3	$ 206.2	$ 20.0	$ 14.8	$ 75.2	$ 150.1	$ 56.2	$ 72.3	$ 123.8	$ 326.3	$ 396.9	$ 2,068.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 17,003.4	$ 11,210.8	$ 6,691.0	$ 973.0	$ 833.2	$ 3,760.9	$ 7,562.2	$ 2,753.8	$ 3,993.5	$ 6,281.1	$ 18,606.9	$ 22,595.3	$ 102,265.0
Net Power Supply Costs ($ x 1000)	$ (7,322.9)	$ 67.1	$ 11,970.2	$ 30,765.4	$ 23,475.5	$ 15,267.6	$ 7,269.1	$ 17,131.4	$ 18,550.5	$ 16,277.9	$ (4,615.7)	$ (8,513.6)	$ 120,322.5
Purchased Power	67.14	64.02	58.81	72.03	70.51	82.28	82.98	84.12	79.95	79.12	91.15	70.79	74.66
Surplus Sales	48.81	42.33	33.46	49.53	57.40	51.04	51.38	49.98	56.25	51.74	58.02	57.93	50.43

IPCO POWER SUPPLY COSTS FOR APRIL 1, 2009 -- MARCH 31, 2010 (Mulitple Gas Prices/80 Years of Hydro)
Repriced Using UE195 Settlement Methodology - October Update
AVERAGE

	April	May	June	July	August	September	October	November	December	January	February	March	Annual
Hydroelectric Generation (MWh)	864,268.9	866,449.0	842,395.2	727,873.1	688,036.5	555,471.4	527,759.4	478,321.1	695,521.7	743,548.7	858,155.2	870,114.3	8,717,914.4
Bridger													
Energy (MWh)	330,372.1	330,372.1	429,803.8	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	5,080,708.9
Cost ($ x 1000)	$ 5,133.8	$ 5,133.8	$ 6,679.0	$ 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	$ 80,447.1
Boardman													
Energy (MWh)	30,791.4	6,410.6	28,422.9	40,365.2	41,031.4	39,532.0	40,965.7	39,726.2	41,067.7	38,748.7	34,978.2	39,163.3	421,203.3
Cost ($ x 1000)	$ 496.8	$ 105.3	$ 471.2	$ 647.2	$ 656.5	$ 632.9	$ 655.6	$ 635.6	$ 657.0	$ 671.7	$ 606.7	$ 678.0	$ 6,914.5
Valmy													
Energy (MWh)	88,830.8	157,350.2	151,362.6	172,657.9	173,151.8	166,575.0	172,391.7	168,288.3	174,160.1	167,583.7	150,037.1	166,302.1	1,908,691.2
Cost ($ x 1000)	$ 2,171.1	$ 3,844.3	$ 3,712.0	$ 4,206.1	$ 4,217.3	$ 4,058.7	$ 4,200.0	$ 4,097.8	$ 4,240.4	$ 4,639.1	$ 4,155.9	$ 4,605.9	$ 48,148.6
Danskin													
Energy (MWh)	64.4	1.0	371.4	18,418.2	9,753.4	1,199.8	613.2	4,822.8	2,289.7	1,199.1	420.0	62.6	39,215.7
Cost ($ x 1000)	$ 6.2	$ 0.1	$ 33.4	$ 1,507.8	$ 794.9	$ 111.1	$ 52.4	$ 428.3	$ 216.0	$ 132.9	$ 47.3	$ 6.6	$ 3,336.8
Fixed Capacity Charge - Gas Transportation ($ x 1000	$ 315.5	$ 296.9	$ 315.5	$ 306.2	$ 315.5	$ 306.2	$ 315.5	$ 315.5	$ 306.2	$ 315.5	$ 306.2	$ 315.5	$ 3,730.3
Total Cost	$ 321.7	$ 297.0	$ 348.9	$ 1,814.0	$ 1,110.4	$ 417.3	$ 367.9	$ 743.8	$ 522.2	$ 448.4	$ 353.5	$ 322.1	$ 7,067.1
Bennett Mountain													
Energy (MWh)	2.4	-	10.4	7,658.1	3,726.1	59.9	14.4	404.8	134.1	70.2	23.8	0.6	12,104.9
Cost ($ x 1000)	$ 0.2	$ -	$ 1.0	$ 658.1	$ 313.7	$ 5.9	$ 1.4	$ 38.0	$ 13.2	$ 8.2	$ 2.8	$ 0.1	$ 1,042.7
Fixed Capacity Charge - Gas Transportation ($ x 1000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ 0.2	$ -	$ 1.0	$ 658.1	$ 313.7	$ 5.9	$ 1.4	$ 38.0	$ 13.2	$ 8.2	$ 2.8	$ 0.1	$ 1,042.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	4,048.0	11,051.7	70,244.5	187,228.9	104,442.2	67,262.7	8,781.5	65,667.7	93,483.4	93,575.4	4,424.8	1,388.2	711,599.0
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)	38,404.0	42,761.0	139,672.0	259,828.5	171,953.5	97,294.3	44,245.0	98,385.7	135,655.4	128,443.6	35,709.0	36,659.1	1,229,011.2
Market Cost ($ x 1000)	$ 225.3	$ 526.8	$ 3,225.8	$ 13,360.3	$ 8,932.5	$ 5,504.1	$ 669.6	$ 5,204.6	$ 7,915.6	$ 7,577.8	$ 357.3	$ 99.4	$ 53,599.3
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)	$ 1,510.2	$ 1,716.8	$ 6,543.6	$ 17,214.7	$ 12,506.0	$ 7,038.5	$ 2,474.3	$ 7,205.4	$ 10,479.2	$ 9,364.2	$ 1,960.4	$ 1,427.0	$ 79,440.3
Surplus Sales													
Energy (MWh)	355,681.0	271,256.5	206,160.4	20,049.8	14,772.6	75,161.1	150,111.6	56,220.7	72,282.3	123,788.2	326,344.6	396,926.6	2,068,755.4
Revenue Including Transmission Costs ($ x 1000)	$ 17,947.4	$ 11,722.9	$ 8,583.6	$ 1,297.2	$ 1,145.6	$ 5,576.9	$ 10,380.9	$ 4,041.0	$ 5,550.7	$ 9,090.7	$ 23,900.3	$ 25,776.5	$ 125,013.7
Transmission Costs ($ x 1000)	$ 355.7	$ 271.3	$ 206.2	$ 20.0	$ 14.8	$ 75.2	$ 150.1	$ 56.2	$ 72.3	$ 123.8	$ 326.3	$ 396.9	$ 2,068.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 17,591.7	$ 11,451.6	$ 8,377.5	$ 1,277.2	$ 1,130.9	$ 5,501.7	$ 10,230.8	$ 3,984.8	$ 5,478.4	$ 8,966.9	$ 23,574.0	$ 25,379.5	$ 122,944.9
Net Hedges													
Energy (MWh)													
Cost($ X 1000)													
Net Power Supply Costs ($ x 1000)	$ (7,957.7)	$ (364.4)	$ 9,378.1	$ 30,336.2	$ 24,746.3	$ 13,496.7	$ 4,541.5	$ 15,580.9	$ 17,506.9	$ 13,766.2	$ (9,628.8)	$ (11,296.8)	$ 100,115.3
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)	$ (4,197.6)	$ 3,471.2	$ 12,796.5	$ 34,557.6	$ 30,036.5	$ 21,160.7	$ 12,661.0	$ 23,508.7	$ 23,921.2	$ 18,382.6	$ (5,564.7)	$ (6,959.3)	$ 163,774.3
Sales at Customer Level (In 000s MWH)	1,023.002	1,059.790	1,234.928	1,447.472	1,514.781	1,410.612	1,159.171	1,103.558	1,242.955	1,344.423	1,275.857	1,150.879	14,967.426
Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
Unit Cost / MWH (for PCAM)	($4.10)	$3.28	$10.36	$23.87	$19.83	$15.00	$10.92	$21.30	$19.25	$13.67	($4.36)	($6.05)	$10.94
Prices Used In Purchased Power & Surplus Sales Above:													
Heavy Load													
Portion of Purchased Power considered HL F	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	
Purchased Power HL Price	60.74	54.42	52.16	79.70	93.67	89.84	80.34	82.84	88.21	86.04	83.08	74.12	
Portion of Surplus Sales considered HL Surp	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	
Surplus Sales HL Price	56.35	50.49	48.39	73.95	86.91	83.36	74.54	76.86	81.84	79.83	77.09	68.77	
Light Load													
Portion of Purchased Power considered LL F	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	
Purchased Power LL Price	46.50	35.54	34.72	56.36	70.89	67.43	68.91	72.82	78.32	71.89	76.56	67.08	
Portion of Surplus Sales considered LL Surp	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	
Surplus Sales LL Price	40.55	30.99	30.27	49.15	61.82	58.80	60.10	63.51	68.30	62.70	66.76	58.50	

Idaho Power Company
Before the Public Utilities Commission of Oregon
State of Oregon
Current and Proposed Rates
12-Months Ending March 2009

Tariff Description	(1) Rate Schedule No	(2) Average No. of Customers	(3) Normalized kWh	(4) Oct 2007 Base Revenue	(5) Revenue Difference	(6) Oct 2008 Base Revenues	(7) Percent Change	(8) Mills per kWh
Uniform Tariff Rates:								
Residential Service	1	13,382	202,245,455	$11,835,370	$452,625	$12,287,995	3.82%	60.7578
Small General Service	7	2,482	17,907,458	1,355,291	40,077	1,395,368	2.96%	77.9211
Large General Service	9	942	131,906,760	7,099,498	295,208	7,394,706	4.16%	56.0601
Dusk to Dawn Lighting	15	-	427,698	113,678	956	114,634	0.84%	268.0256
Large Power Service	19	8	275,841,256	10,425,388	617,333	11,042,721	5.92%	40.0329
Irrigation Service	24	1,457	63,726,546	3,129,171	142,620	3,271,791	4.56%	51.3411
Unmetered General Service	40	3	13,124	811	29	840	3.58%	64.0049
Municipal Street Lighting	41	13	842,094	113,052	1,884	114,936	1.67%	136.4883
Traffic Control Lighting	42	6	17,574	841	39	880	4.64%	50.0740
Total Uniform Tariffs		18,293	692,927,965	$34,073,100	$1,550,771	$35,623,871	4.55%	51.4106

SCHEDULE 55
ANNUAL POWER COST UPDATE
(Continued)

APCU - MARCH FORECAST (Continued)

Purchased Power

- Heavy Load - 3.9% above average Mid-C HL prices
- Light Load - 7.1% above average Mid-C LL prices

Surplus Sales

- Heavy Load - 3.6% below average Mid-C HL prices
- Light Load - 6.6% below average Mid-C LL prices

The March Forecast Rate for power supply expense will be the Forecast Power Costs determined by the procedures described above, divided by the Forecast Normalized sales.

CHANGES IN NET POWER SUPPLY EXPENSE

Changes in NPSE are defined as the projected per unit change in NPSE from the per unit NPSE used to develop the Energy Charge for the applicable rate schedules. Unit NPSE are defined as the total NPSE divided by Normalized Sales for the April through March Test Period.

FILING AND EFFECTIVE DATE

In October of each year, the Company will file its October Update with an effective date of June 1 of the following year.

In March of each year the Company will file its March Forecast with an effective date of June 1 following the filing.

RATE ADJUSTMENT

The Sales Adjusted Forecast Power Cost Change is the March Forecast Rate less the October Update Rate, the result multiplied by the Forecast Sales.

The Forecast Change Allowed is 95% of the Sales Adjusted Forecast Power Cost charge.

The March Forecast Rate Adjustment is the Forecast Change Allowed divided by Forecast Sales.

The Combined Rate is the sum of the October Update Rate and the March Forecast Rate Adjustment.

The rate adjustment is the difference between the Combined Rate and the unit NPSE included in the current base rate. The rate adjustment is applied to each of the schedules on an equal cents per kWh basis.

ADJUSTMENT RATES

Schedule	Description	¢ per kWh	
1	Residential Service	0.8990	(I)
7	Small General Service	0.8990	
9	Large Power Service	0.8990	
15	Dusk to Dawn Lighting	0.8990	
19	Large Power Service	0.8990	
24	Irrigation Service	0.8990	
40	Unmetered General Service	0.8990	
41	Municipal Street Lighting	0.8990	
42	Traffic Control Lighting	0.8990	(I)