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March 21, 2014

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VIA ELECTRONIC AND U.S. MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088

Re: UE 279 In The Matter of IDAHO POWER COMPANY's 2014 Annual Power Cost Update

Attention Filing Center:

Enclosed for filing in the above-referenced matter is an original and five 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. Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Enclosures
cc: Service List

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BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 279

IN THE MATTER OF IDAHO POWER COMPANY'S 2014 ANNUAL POWER COST UPDATE	)
	)
MARCH FORECAST	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

SCOTT WRIGHT

March 21, 2014

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

A. Yes. I previously submitted testimony in this proceeding regarding the October Update for the 2014 Annual Power Cost Update ("APCU"). The 2014 October Update is Idaho Power Company's ("Company") estimate of what "normalized" power supply expenses will be for the upcoming APCU test period of April 2014 through March 2015.

Q. What is the status of the October Update in this proceeding?

A. The Company filed the 2014 October Update on October 18, 2013, and Staff of the Public Utility Commission of Oregon and the Citizens' Utility Board of Oregon reviewed the filing. Several rounds of discovery requests were served on the Company after the initial filing. On January 13, 2014, a settlement conference was held with all parties. At the conclusion of the settlement conference, all parties agreed to a per-unit cost of $21.82 per megawatt-hour ("MWh") for the 2014 October Update. On February 5, 2014, a Partial Stipulation was filed by all intervening parties agreeing to the per-unit cost of $21.82 per MWh.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the second part of the Company's APCU filing, which is the March Forecast 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 ("NPSE") for the APCU test period of April through March, as determined by the AURORA model.

Q. How does the March Forecast differ from the October Update?

A. The October Update is calculated by simulating 85 water year conditions in the AURORA model and then averaging the results of all 85 NPSE to create an "average" or "normal" expectation of NPSE. In contrast, the March Forecast is calculated by simulating the "expected" water condition during the upcoming APCU test period based on the most recent water supply forecast and current reservoir levels from the Northwest River Forecast Center ("NRFC") in Portland, Oregon. The results for the October Update are used to update base rates, while the results for the March Forecast are used to update Schedule 55, Annual Power Cost Update.

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

A. The following variables are described 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 NRFC and current reservoir levels;

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

h. Forward price curve as defined below;

i. Public Utilities Regulatory Policies Act of 1978 ("PURPA") contract expenses; and

j. The Oregon state allocation factor.

Q. After reviewing all of the inputs used for the October Update, 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 2014 through March 2015 test period only the following variables have changed since the October APCU determination was prepared: (1) fuel prices; (2) heat rates; (3) forecast of normalized sales and loads; (4) forecast of hydro generation and current reservoir levels from stream flow conditions using the most recent water supply forecast from the NRFC; (5) known power purchases and surplus sales from the Company's Risk Management Policy; (6) forward price curve; and (7) PURPA contract expenses.

Q. Please describe why the fuel prices have changed since the October Update was filed?

A. The coal and gas price forecasts are refreshed monthly for operational planning purposes. When the October Update was prepared, information from the September 2013 Operations Plan was used. The March Forecast determination of NPSE includes the Company's most current coal and gas price forecasts.

Q. What impact does the current coal price forecast have on the per-unit cost of output when compared to the October Update results?

A. The per-unit cost of output from AURORA in terms of dollars per MWh increased at the Jim Bridger power plant ("Bridger") from $22.70 per MWh to $26.44 per MWh, decreased at the Boardman power plant ("Boardman") from $26.71 per MWh to $23.98 per MWh and decreased slightly at the Valmy power plant ("Valmy") from $35.58 per MWh to $35.38 per MWh. The output cost from AURORA includes both variable and fixed fuel components as well as the inclusion of any start up costs.

Q. What factors drove the changes in the coal price forecast since the October Update was filed?

A. The increase in the per-unit cost of coal for the Bridger plant is attributed to increased mining costs at Bridger Coal Company. Bridger Coal Company produces coal through two mining techniques, surface mining and underground mining. Over the last few years, the majority of coal production at Bridger Coal Company has come from underground mining. Since the October Update was filed, the underground mining cost for Bridger Coal Company has increased due to lower coal quality, increased development costs, and decreased production. The combination of those factors coupled with the delivery of more expensive coal in inventory has increased the per ton cost of coal delivered from Bridger Coal Company.

The decrease in the per-unit cost of coal for the Boardman plant can be attributed to changes in contract estimates. When the October Update was filed, several contract values had not yet been finalized, so estimates were used. In 2014, contracts were executed and the estimates used in the October Update were replaced with actual values for the March Forecast, which resulted in a decrease from the October Update.

The relatively small decrease in the per-unit cost of output at the Valmy plant can be attributed to some of the same changes described above with Boardman. The contract cost for coal was reduced from the October Update, while the variable operations and maintenance portion increased at a smaller rate, therefore offsetting each other at a slight per-unit cost decrease.

Q. How did the gas price forecast included in the March Forecast change as compared to the gas price forecast included in the October Update?

A. The gas price forecast used for the October Update for Henry Hub was $4.08 per MMBtu, while the gas price forecast used for the March Forecast for Henry Hub has increased to $4.41 per MMBtu, an increase of $0.33 per MMBtu. The increase in the Henry Hub price from the October Update to the March Forecast is driven by increased use of natural gas from the Midwest and Eastern United States this winter. The increased gas consumption used larger amounts of natural gas storage than previous years that will need to be replaced this summer. The higher gas prices will either entice greater production levels or reduce consumption in order to replenish storage levels for next winter.

Q. Please explain how the Henry Hub gas price forecast is used as an AURORA input.

A. The Company uses the gas price forecast for Henry Hub as the starting point in the AURORA model. Henry Hub is considered a reference fuel in AURORA, meaning other gas prices reference Henry Hub and apply a basis in order to develop their price. For example, a Henry Hub gas price of $4.41 per MMBtu applied to a Sumas basis of $0.05 per MMBtu equals a Sumas gas price of $4.46 per MMBtu ($4.41 + $0.05 = $4.46). The Company also develops a gas price for its natural gas units based off of the Henry Hub gas price forecast.

Q. Why was the heat rate adjusted between the October Update and March Forecast?

A. The Company uses a twelve-month ending heat rate for modeling purposes. Because there was a six-month gap between the October Update and March Forecast, the twelve-month ending heat rate was refreshed to reflect the six new months. In this case, the Boardman plant experienced some minor improvements in its heat rate, while Bridger and Valmy remained the same.

Q. Please explain the magnitude of change between the forecast of normalized sales used in the October Update and March Forecast.

A. The forecast of normalized sales used for the October Update was expected to be 1,780 average megawatts ("aMW"). The forecast of normalized sales used for the March Forecast is expected to be 1,787 aMW, an increase of 7 aMW. The updated sales and load forecast includes updated economic information as well as updated sales and customer data for all classes; when combined together increase the sales and load forecast slightly from the sales and load forecast used in the October Update. The overall increase between the sales and load forecast used for the March Forecast compared to the October Update is less than a one percent increase.

Q. What was the date of the water supply forecast from the NRFC that was used to create the hydro generation forecast for the March Forecast?

A. The forecast of monthly hydro generation levels included in the March Forecast reflects the NRFC's March 7, 2014, forecast ("March 7th Forecast") and current reservoir levels. The March 7th Forecast has expected inflows into Brownlee Reservoir for April through July of 3.86 million acre-feet ("MAF"), or 71 percent of the (1981-2010) average level of 5.47 MAF.

Q. How does this year's water supply forecast compare to last year's NRFC's forecast?

A. The NRFC's forecast used in last year's March Forecast was 3.74 MAF compared to this year's forecast of 3.86 MAF, which is 3 percent higher than last year, but still below the 30-year average by 1.61 MAF.

Q. What significance does a lower than average stream flow forecast have on the Company's variable power supply expenses?

A. Because a significant portion of the Company's generation fleet is hydro-based, a lower than average stream flow forecast has a detrimental effect on the Company's variable power supply expenses. The hydro generation forecasted under the normalized scenario for the October Update was 8.5 million MWh, while the hydro generation forecasted under this year's March Forecast is 7.1 million MWh, a decrease of 1.4 million MWh or 160 aMW. To put things in perspective, the combined expected output from Langley Gulch, Valmy, and Boardman for the October Update equaled 170 aMW, almost equal to the difference in hydro generation between the October Update and March Forecast. Higher reliance on those resources is now reflected in the March Forecast.

The lower than average hydro generation used for the March Forecast resulted in the following impacts to NPSE as compared to the October Update: (1) coal generation increased by 406,039 MWh; (2) gas generation increased by 28,671 MWh; (3) known power purchases and surplus sales from the Company's Risk Management Policy account for 340,400 MWh of additional purchased power, while market purchased power volumes in AURORA remained relatively stable; (4) surplus sales volumes, which are a direct benefit to customers decreased by 743,691 MWh.

Q. Did the Company include known power purchases and surplus sales resulting from the Company's Risk Management Policy in the March Forecast?

A. Yes. The Company includes known power purchases and surplus sales resulting from the Company's Risk Management Policy and incorporates those amounts as Net Hedges on Exhibit No. 202, as directed by Order No. 08-238.

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

A. Exhibit No. 201 shows the March 10, 2014, Mid-Columbia forward price curve for the April 2014 through March 2015 test period the Company used, as directed by Order No. 08-238.

Q. Did the Company update its PURPA contract expenses for the March Forecast?

A. Yes. Since the October Update was filed, one additional PURPA contract is expected to be operational during the April 2014 through March 2015 test period, while one PURPA contract was removed for not meeting contractual obligations.

Q. How does the total PURPA expense included in the March Forecast compare to the level of total PURPA expense included in the October Update?

A. The total PURPA expense included in the March Forecast is $165.5 million compared to the $165.9 million included in the October Update, a decrease of $0.4 million.

Q. Were there any other changes to the modeling inputs that occurred between the October Update and March Forecast that are not specifically addressed by Order No. 08-238?

A. Yes. The Company updated the hourly energy profiles for Elkhorn Wind, PURPA Wind, and Raft River Geothermal from a 2012 historical hourly profile to a 2013 historical hourly profile. The generation input for Neal Hot Springs was also changed from a monthly profile to an hourly profile.

Q. Why did the Company change the generation input for Neal Hot Springs from a monthly profile to an hourly profile?

A. Neal Hot Springs became operational in November of 2012. Therefore, when the October Update was filed, a historical hourly production profile was not available. Because the 2013 historical hourly production profile for Neal Hot Springs was available at the time the March Forecast was prepared, generation from that plant is now being modeled like Elkhorn Wind and Raft River Geothermal, which are both purchased power agreements.

Q. What is the Company's March Forecast of net power supply expense as a result of the changes described above?

A. Exhibit No. 202 shows the results of a single water condition for the April 2014 through March 2015 test period, with updated heat rates, fuel prices, normalized sales and load, updated stream flow conditions and reservoir levels, updated power purchases and surplus sales from the Company's Risk Management Policy (Net Hedges), market purchased power and surplus sales repriced, updated PURPA contract expenses, and updated hourly load profiles for Elkhorn Wind, PURPA Wind, Neal Hot Springs, and Raft River Geothermal. The March Forecast for NPSE without PURPA is $208.4 million. When PURPA expenses of $165.4 million are included, the total NPSE for the March Forecast is $373.8 million.

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

A. Exhibit No. 202 shows the normalized annual sales at the customer level for the April 2014 through March 2015 test period are 14,252,876 MWh. Based upon test period sales, the cost per-unit for the March Forecast to become effective on June 1, 2014, is $26.23 per MWh ($373.8 million / 14.252 million MWh = $26.23 per MWh).

Q. How does this $26.23 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 2013 through March 2014 test period was $25.49 per MWh, as compared to this year's April 2014 through March 2015 test period of $26.23 per MWh, an increase of $0.74 per MWh.

Q. Please describe the calculation necessary to determine the March Forecast Rate Adjustment.

A. Exhibit No. 203 steps through the Commission specified method of calculating the March Forecast Rate, pursuant to Order No. 08-238. Lines 1-3 show the calculation for the October Update Stipulation agreed upon rate of $21.82 per MWh. Lines 4-6 show the calculation for the March Forecast Rate of $26.23 per MWh. Line 7 is calculated by the March Forecast Rate minus the October Update 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 percent) 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 of $4.19 per MWh.

Q. Please explain how the incremental revenue requirement for the March Forecast is calculated using the March Forecast Rate Adjustment unit cost of $4.19 per MWh.

A. The incremental revenue requirement for the March Forecast is calculated by multiplying the unit cost of $4.19 per MWh by the loss adjusted Oregon jurisdictional sales for the April 2014 through March 2015 test period of 639,264.818 MWh, creating a revenue deficiency of $2.7 million.

Q. What method of allocation are you proposing to spread the incremental revenue requirement associated with the March Forecast to the various customer classes?

A. I am proposing to allocate the revenue deficiency associated with the 2014 March Forecast according to the revenue spread methodology approved by the Commission in UE 214, Order No. 10-191. Order No. 10-191 established a revenue spread methodology whereby the revenue deficiency for the March Forecast is allocated to individual customer classes on the basis of the total generation-related revenue requirement approved in the Company's last general rate case. In this instance, the Company's last general rate case, UE 233, was a settled case in which parties did not adopt the Company's class cost-of-service methodology, but rather agreed to a revenue spread methodology that was set forth in Exhibit B to the Partial Stipulation filed on February 1, 2012. In light of the stipulated revenue spread, the Company has utilized the total generation-related revenue requirement detailed on Exhibit B to the Partial Stipulation to apportion the March Forecast revenue requirement to each customer class. The proposed revenue spread resulting from the application of the stipulated methodology in UE 233 is shown on Exhibit 204.

Q. Did the Company revise the revenue spread for the October Update?

A. Yes. The Company revised the revenue spread for the October Update to align with the loss adjusted sales that were used for the March Forecast filing. This practice of updating the revenue spread for the October Update is consistent with the method applied in UE 242 and UE 257, the Company's last two APCU filings. The loss adjusted sales used for the October Update were 1,078 MWh lower than the loss adjusted sales used for the March Forecast filing (1,078 MWh = October Update 638,186.407 MWh – March Forecast 639,264.818 MWh). The change in loss adjusted sales decreases the October Update revenue requirement by $1,413 ($1,413 = October Settlement of ($836,024) – Updated October Update to reflect new loss adjusted sales of ($837,437)). Exhibit 204 also shows the revised revenue spread for the October Update.

Q. What is the overall revenue impact of this year's combined October Update and March Forecast compared to last year's combined October Update and March Forecast using the rate spread methodology described above?

A. The overall revenue impact of this year's combined October Update and March Forecast is an increase of approximately $0.4 million or 0.82 percent overall. The $0.4 million increase reflects the $1.8 million associated with the 2014 APCU (October Update and March Forecast) less the $1.4 million currently included in Oregon customers' rates related to the 2013 APCU.

Q. Have you supervised the preparation of an exhibit showing the summary of revenue impact resulting from the combined October Update and March Forecast proposed by the Company?

A. Yes. Exhibit No. 205 provides a summary of the revenue change resulting from this year's combined October Update and March Forecast as compared to current revenue.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 279
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright

March 10, 2014, Mid-Columbia Price Curve for April 2014 – March 2015

March 21, 2014

IDAHO POWER COMPANY
Mid-Columbia Heavy Load and Light Load Daily Forward Curves
Used to Re-Price Purchased Power (PP) and Surplus Sales (SS) for the March Forecast

Line	Mid-Columbia Forward Price Curve on:												
1	**3/10/2014**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**
2	**mc HL**	30.10	28.55	26.95	43.00	52.50	49.65	45.00	44.70	50.30	42.55	42.50	42.50
3	**mc LL**	16.25	12.90	10.00	20.75	35.25	37.25	37.55	37.90	42.85	36.30	36.20	36.25
4	**Reallocated Prices**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**
5	**HL PP**												
6	103.9%	31.27	29.66	28.00	44.68	54.55	51.59	46.76	46.44	52.26	44.21	44.16	44.16
7	**LL PP**												
8	107.1%	17.40	13.82	10.71	22.22	37.75	39.89	40.22	40.59	45.89	38.88	38.77	38.82
9	**HL SS**												
10	96.4%	29.02	27.52	25.98	41.45	50.61	47.86	43.38	43.09	48.49	41.02	40.97	40.97
11	**LL SS**												
12	93.4%	15.18	12.05	9.34	19.38	32.92	34.79	35.07	35.40	40.02	33.90	33.81	33.86

Idaho Power/202
Witness: Scott Wright

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 279
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright

Power Supply Costs for April 1, 2014 – March 31, 2015

March 21, 2014

IPCO POWER SUPPLY EXPENSES FOR APRIL 1, 2014 – MARCH 31, 2015 (One Hydro Condition)
Repriced Using UE 195 Settlement Methodology - March Forecast

	April	May	June	July	August	September	October	November	December	January	February	March	Annual
Hydroelectric Generation (MWh)	725,715.9	799,764.2	645,913.5	644,313.0	394,943.0	342,948.8	431,438.8	402,928.0	476,479.8	658,609.6	810,248.6	774,465.6	7,107,768.9
Bridger													
Energy (MWh)	238,732.9	285,565.2	282,464.0	466,760.5	472,305.9	443,647.0	472,876.5	456,370.0	479,361.0	483,393.1	406,224.6	403,533.6	4,891,234.4
Expense ($ x 1000)	$ 6,630.8	$ 7,866.4	$ 7,849.6	$ 12,377.1	$ 12,490.5	$ 11,761.7	$ 12,502.6	$ 12,073.4	$ 12,634.8	$ 12,365.2	$ 10,414.7	$ 10,361.1	$ 129,327.7
Boardman													
Energy (MWh)	5,123.8	5,530.1	27,298.0	41,426.1	41,683.4	39,314.1	41,192.6	39,887.5	41,683.4	26,691.3	15,556.4	18,120.8	343,507.4
Expense ($ x 1000)	$ 117.6	$ 130.2	$ 649.8	$ 945.5	$ 950.6	$ 899.5	$ 940.8	$ 910.9	$ 950.6	$ 736.5	$ 467.1	$ 538.8	$ 8,238.0
Valmy													
Energy (MWh)	-	7,465.0	-	49,078.7	73,058.8	44,705.9	77,694.0	71,376.2	120,940.0	18,275.3	-	-	462,593.9
Expense ($ x 1000)	$ -	$ 281.9	$ -	$ 1,742.7	$ 2,585.3	$ 1,585.9	$ 2,746.3	$ 2,510.0	$ 4,211.8	$ 702.1	$ -	$ -	$ 16,365.9
Langley Gulch													
Energy (MWh)	-	53,406.6	36,613.6	134,683.0	143,488.8	133,137.7	138,542.5	106,213.6	100,750.6	48,510.6	9,713.0	7,260.9	912,320.8
Expense ($ x 1000)	$ -	$ 1,587.3	$ 1,078.0	$ 4,027.8	$ 4,384.3	$ 4,039.6	$ 4,271.9	$ 3,557.0	$ 3,585.5	$ 1,714.1	$ 335.2	$ 244.3	$ 28,824.9
Danskin													
Energy (MWh)	-	-	-	1,124.1	1,538.8	67.9	33.7	-	-	-	-	-	2,764.5
Expense ($ x 1000)	$ -	$ -	$ -	$ 54.1	$ 76.1	$ 3.3	$ 1.7	$ -	$ -	$ -	$ -	$ -	$ 135.2
Bennett Mountain													
Energy (MWh)	-	-	-	179.2	448.5	-	-	-	-	-	-	-	627.6
Expense ($ x 1000)	$ -	$ -	$ -	$ 8.7	$ 22.4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 31.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 739.2	$ 763.2	$ 748.2	$ 781.8	$ 781.8	$ 757.2	$ 763.2	$ 739.2	$ 763.2	$ 763.2	$ 691.1	$ 763.2	$ 9,054.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	14,417.5	17,702.8	151,460.6	69,282.2	159,521.3	104,510.3	646.9	17,619.2	10,163.4	38,817.5	2,331.9	2,684.1	589,157.6
Elkhorn Wind Energy (MWh)	28,001.1	21,581.8	26,120.8	28,186.0	27,014.8	24,128.2	20,993.4	19,976.0	24,508.5	30,125.9	23,189.5	22,954.5	296,780.5
Neal Hot Springs Energy (MWh)	6,144.0	6,713.0	4,390.0	6,243.0	6,281.0	6,164.0	7,126.0	7,216.0	7,578.0	6,331.0	6,683.0	6,670.0	77,538.9
Raft River Geothermal Energy (MWh)	10,449.4	8,974.6	9,226.6	6,856.5	8,582.3	9,219.9	14,568.3	17,362.2	19,110.9	16,623.4	13,816.1	13,618.5	148,408.8
Total Energy Excl. CSPP (MWh)	59,012.0	54,972.2	191,198.1	110,567.7	201,399.4	144,022.4	43,334.6	62,173.4	61,360.8	91,897.7	46,020.5	45,927.1	1,111,885.8
Market Expense ($ x 1000)	$ 304.4	$ 477.9	$ 3,172.1	$ 2,729.7	$ 7,486.6	$ 5,145.8	$ 30.2	$ 809.1	$ 483.6	$ 1,669.9	$ 94.9	$ 108.1	$ 22,512.3
Elkhorn Wind Expense ($ x 1000)	$ 1,141.6	$ 879.9	$ 1,448.9	$ 1,876.1	$ 1,798.1	$ 1,338.3	$ 1,164.4	$ 1,329.6	$ 1,631.3	$ 1,721.1	$ 1,324.8	$ 963.9	$ 16,618.0
Neal Hot Springs Expense ($ x 1000)	$ 274.2	$ 299.6	$ 266.6	$ 454.9	$ 457.7	$ 374.3	$ 432.7	$ 525.8	$ 552.2	$ 392.5	$ 414.3	$ 304.0	$ 4,748.6
Raft River Geothermal Expense ($ x 1000)	$ 787.2	$ 676.1	$ 948.3	$ 845.7	$ 1,058.5	$ 947.6	$ 1,497.3	$ 2,141.4	$ 2,357.1	$ 1,775.2	$ 1,475.4	$ 1,066.0	$ 15,575.9
Total Expense Excl. CSPP ($ x 1000)	$ 2,507.4	$ 2,333.5	$ 5,835.9	$ 5,906.3	$ 10,800.8	$ 7,806.0	$ 3,124.7	$ 4,805.9	$ 5,024.1	$ 5,558.7	$ 3,309.5	$ 2,441.9	$ 59,454.9
Surplus Sales													
Energy (MWh)	167,323.4	181,577.5	61,553.8	102,306.5	18,349.7	56,526.8	276,324.7	138,608.8	100,739.6	88,363.1	285,369.9	245,123.7	1,722,167.6
Revenue Including Transmission Costs ($ x 1000)	$ 4,161.2	$ 3,310.4	$ 1,125.7	$ 2,849.2	$ 772.4	$ 2,150.3	$ 10,855.5	$ 5,306.9	$ 4,527.8	$ 3,280.7	$ 10,950.6	$ 9,287.3	$ 58,578.1
Transmission Costs ($ x 1000)	$ 167.3	$ 181.6	$ 61.6	$ 102.3	$ 18.3	$ 56.5	$ 276.3	$ 138.6	$ 100.7	$ 88.4	$ 285.4	$ 245.1	$ 1,722.2
Revenue Excluding Transmission Costs ($ x 1000)	$ 3,993.9	$ 3,128.9	$ 1,064.1	$ 2,746.9	$ 754.1	$ 2,093.8	$ 10,579.2	$ 5,168.3	$ 4,427.1	$ 3,192.3	$ 10,665.2	$ 9,042.1	$ 56,855.9
Net Hedges													
Energy (MWh)	-	-	60,000.0	189,000.0	91,400.0	-	-	-	-	-	-	-	340,400.0
Cost($ X 1000)	$ -	$ -	$ 1,740.0	$ 7,384.2	$ 4,705.4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,829.6
Net Power Supply Expenses ($ x 1000)	$ 6,001.0	$ 9,833.7	$ 16,837.3	$ 30,481.2	$ 36,043.1	$ 24,759.4	$ 13,772.0	$ 19,428.2	$ 22,743.0	$ 18,647.5	$ 4,552.3	$ 5,307.2	$ 208,405.8
PURPA ($ x 1000)	$ 17,478.8	$ 15,752.6	$ 14,267.6	$ 13,046.6	$ 12,945.9	$ 12,346.1	$ 10,919.9	$ 12,047.7	$ 10,612.6	$ 13,487.3	$ 15,606.5	$ 16,935.5	$ 165,447.1
Total Net Power Supply Expenses ($ x 1000)	$ 23,479.8	$ 25,586.3	$ 31,104.9	$ 43,527.8	$ 48,989.0	$ 37,105.5	$ 24,691.8	$ 31,475.9	$ 33,355.5	$ 32,134.8	$ 20,158.8	$ 22,242.7	$ 373,852.9
Sales at Customer Level (In 000s MWH)	1,012.646	1,016.293	1,174.242	1,420.002	1,505.694	1,353.288	1,086.391	1,017.541	1,140.063	1,258.906	1,182.472	1,085.339	14,252.876
Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
Unit Cost / MWH (for PCAM)	$23.19	$25.18	$26.49	$30.65	$32.54	$27.42	$22.73	$30.93	$29.26	$25.53	$17.05	$20.49	$26.23
Prices Used In Purchased Power & Surplus Sales Above:													
Heavy Load													
Portion of Purchased Power considered HL I	26.74%	83.18%	59.18%	76.50%	54.65%	79.91%	99.74%	91.10%	26.51%	77.67%	35.72%	27.05%	
Purchased Power HL Price	31.27	29.66	28.00	44.68	54.55	51.59	46.76	46.44	52.26	44.21	44.16	44.16	
Portion of Surplus Sales considered HL Sur	70.03%	39.96%	53.77%	38.37%	51.86%	24.86%	50.72%	37.55%	58.15%	45.31%	63.73%	56.67%	
Surplus Sales HL Price	29.02	27.52	25.98	41.45	50.61	47.86	43.38	43.09	48.49	41.02	40.97	40.97	
Light Load													
Portion of Purchased Power considered LL F	73.26%	16.82%	40.82%	23.50%	45.35%	20.09%	0.26%	8.90%	73.49%	22.33%	64.28%	72.95%	
Purchased Power LL Price	17.40	13.82	10.71	22.22	37.75	39.89	40.22	40.59	45.89	38.88	38.77	38.82	
Portion of Surplus Sales considered LL Surp	29.97%	60.04%	46.23%	61.63%	48.14%	75.14%	49.28%	62.45%	41.85%	54.69%	36.27%	43.33%	
Surplus Sales LL Price	15.18	12.05	9.34	19.38	32.92	34.79	35.07	35.40	40.02	33.90	33.81	33.86	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 279
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright

Annual Power Cost Update for April 2014 – March 2015

March 21, 2014

ANNUAL POWER COST UPDATE
April 2014 - March 2015

Line		
	OCTOBER APCU	
1	Forecast of Normalized Sales (MWh)	14,186,526
2	Total Net Power Supply Expense	$309,610,753
3	October APCU Rate ($/MWh)	$21.82
	MARCH FORECAST	
4	Forecast of Normalized Sales (MWh)	14,252,876
5	Total Net Power Supply Expense	$373,852,857
6	March Forecast Rate ($/MWh)	$26.23
7	Sales Adjusted Forecast Power Cost Change	$62,855,183
8	Portion of Change Allowed	95%
9	Forecast Change Allowed	$59,712,424
10	**March Forecast Rate Adjustment ($/MWh)**	$4.19
11	**Combined Rate ($/MWh)**	$26.01

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 279
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright

Revenue Spread for October Update and March Forecast

March 21, 2014

Idaho Power Company
Rate Spread Exhibit for October Update APCU

General Rate Case (UE 233): Marginal Cost-of-Service Study and Stipulated Revenue Spread
2011 Test Period

Line	Description	(A) TOTAL SYSTEM	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(F) GEN SRV TRANS (9-T)	(G) AREA LIGHTING (15)	(H) LG POWER PRIMARY (19-P)	(I) LG POWER TRANS (19-T)	(J) IRRIGATION SECONDARY (24-S)	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)
1	**Normalized Sales (kWh)**	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
2	**Current Revenue**	$39,873,591	$15,355,932	$1,559,400	$6,975,915	$798,102	$154,997	$112,462	$8,213,065	$3,123,393	$3,454,271	$972	$123,851	$1,231
3														
4	**Demand Related Marginal Cost**													
5	Generation - Staff Adj.	$11,049,450	$4,082,443	$268,043	$1,671,178	$207,813	$35,425	$625	$1,790,415	$1,483,718	$1,508,400	$158	$1,035	$200
6	Transmission - Staff Adj.	$12,432,118	$4,593,297	$301,584	$1,880,300	$233,817	$39,858	$703	$2,014,458	$1,669,382	$1,697,153	$177	$1,165	$225
7	Distribution	$6,945,625	$3,215,110	$181,233	$1,319,947	$100,783	$0	$5,738	$798,946	$0	$1,314,267	$161	$9,350	$89
8														
9	**Energy Related Marginal Cost**													
10	Generation	$28,547,004	$8,940,577	$802,452	$5,140,232	$649,911	$117,743	$21,383	$7,662,010	$3,097,424	$2,079,568	$570	$34,414	$722
11	Transmission - Staff Adj.	$4,144,040	$1,297,863	$116,488	$746,184	$94,345	$17,092	$3,104	$1,112,259	$449,639	$301,881	$83	$4,996	$105
12														
13	**Simple-Summed Energy-Related and Demand-Related Marginal Costs**													
14	Generation Marginal Costs - Staff Adj.	$39,596,454	$13,023,020	$1,070,495	$6,811,410	$857,724	$153,168	$22,008	$9,452,425	$4,581,142	$3,587,968	$728	$35,449	$922
15	Transmission Marginal Costs - Staff Adj.	$16,576,157	$5,891,160	$418,072	$2,626,484	$328,162	$56,950	$3,807	$3,126,717	$2,119,021	$1,999,034	$260	$6,160	$330
16														
17	**Customer Related Marginal Cost**	$2,805,903	$1,967,110	$385,570	$177,410	$6,719	$1,390	$0	$15,208	$2,535	$246,967	$228	$1,892	$873
18														
19	**Total Functionalized Revenue Requirement**													
20	Generation - Staff Adj.	$25,202,690	$8,289,003	$681,357	$4,335,384	$545,931	$97,490	$14,008	$6,016,360	$2,915,844	$2,283,701	$463	$22,563	$587
21														
22	Transmission	$4,272,366	$1,518,397	$107,755	$676,954	$84,581	$14,678	$981	$805,885	$546,160	$515,234	$67	$1,588	$85
23														
24	Distribution													
25	Demand-Related	$8,930,530	$4,133,917	$233,025	$1,697,158	$129,585	$0	$7,378	$1,027,267	$0	$1,689,855	$207	$12,022	$114
26	Customer-Related													
27	Allocated	$2,859,472	$2,004,665	$392,931	$180,797	$6,847	$1,417	$0	$15,498	$2,583	$251,682	$232	$1,928	$890
28	Direct Assignment	$419,424	$188,447	$34,356	$12,375	$69	$14	$78,778	$83	$14	$21,953	$42	$83,209	$83
29														
30	**Total: Staff-Adjusted Allocation**	$41,684,482	$16,134,429	$1,449,425	$6,902,669	$767,013	$113,599	$101,145	$7,865,094	$3,464,601	$4,762,425	$1,011	$121,310	$1,759
31	**Revenue Deficiency - Staff Adj. Allocation**	$1,810,890	$778,497	($109,975)	($73,246)	($31,089)	($41,398)	($11,317)	($347,971)	$341,208	$1,308,154	$39	($2,541)	$528
32	**% Increase Required by Staff Adj. Alloc. Approach**	4.54%	5.07%	-7.05%	-1.05%	-3.90%	-26.71%	-10.06%	-4.24%	10.92%	37.87%	4.02%	-2.05%	42.91%
33	**$ Increase Recommended per Stipulation**	**$1,810,890**	**$862,348**	**$44,153**	**$197,517**	**$22,598**	**$0**	**$0**	**$232,545**	**$212,777**	**$235,318**	**$44**	**$3,507**	**$84**
34	**% Increase Recommended per Stipulation**	**4.54%**	**5.62%**	**2.83%**	**2.83%**	**2.83%**	**0.00%**	**0.00%**	**2.83%**	**6.81%**	**6.81%**	**4.56%**	**2.83%**	**6.81%**
35	**Average Rate Given Stipulation ($/kWh)**	**0.0641**	**0.0816**	**0.0899**	**0.0628**	**0.0544**	**0.0547**	**0.2324**	**0.0471**	**0.0450**	**0.0791**	**0.0788**	**0.1637**	**0.0805**
36	**Final Revenue Allocation**	$41,684,481	$16,218,280	$1,603,553	$7,173,432	$820,700	$154,997	$112,462	$8,445,610	$3,336,170	$3,689,589	$1,016	$127,358	$1,315
37														
38	**Spread Floors and Ceilings:**													
39	No increase for those warranting a decrease greater than 8%													
40	2.83% increase for those warranting a decrease less than 8%													
41	No increase greater than one-and-one-half times the average increase													
	2012 October Update APCU (UE 242): Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures													
42	2012 October Update APCU Cost of Service (UE 242)	$1,298,993	$427,230	$35,118	$223,454	$28,138	$5,025	$722	$310,094	$150,288	$117,706	$24	$1,163	$30
	2013 October Update APCU (UE 257): Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures													
43	2013 October Update APCU Cost of Service (UE 257)	$2,298,531	$755,972	$62,141	$395,395	$49,790	$8,891	$1,278	$548,703	$265,930	$208,278	$42	$2,058	$54
	2014 October Update APCU: Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures													
44	2014 October Update APCU Cost of Service (Allocator -- Line 14)	-$837,437	-$275,428	-$22,640	-$144,056	-$18,140	-$3,239	-$465	-$199,912	-$96,888	-$75,883	-$15	-$750	-$19
45	% Increase Required Due to APCU (Proposed) (Line 44/(Line 36)	-2.01%	-1.70%	-1.41%	-2.01%	-2.21%	-2.09%	-0.41%	-2.37%	-2.90%	-2.06%	-1.51%	-0.59%	-1.48%
46	Proposed Combined Revenue Spread (Line 36 + Line 42 + Line 43 +	$44,444,567	$17,126,055	$1,678,172	$7,648,224	$880,487	$165,674	$113,996	$9,104,495	$3,655,500	$3,939,689	$1,067	$129,829	$1,379
47	Loss-Adjusted 2011 Normalized Sales (kWh)	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
48	2014 October Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*(Line 44/Line 47))	-1.288	-1.385	-1.269	-1.261	-1.201	-1.144	-0.962	-1.116	-1.307	-1.627	-1.193	-0.964	-1.194
49	**APCU Incremental Rate for 2014 October Update (Mills per kWh) (Line 48*(Column A:[Line 47/Line 50]))**	**-1.310**	**-1.463**	**-1.256**	**-1.268**	**-1.071**	**-1.318**	**-1.017**	**-1.163**	**-1.170**	**-1.728**	**-1.750**	**-0.845**	**-0.928**
50	*Loss-Adjusted 2014-2015 Normalized Sales (kWh)*	639,264,818	188,282,848	18,025,844	113,647,734	16,942,598	2,457,786	457,839	171,834,384	82,791,791	43,907,465	8,791	886,721	21,017
51	Projected October Update APCU 2014-2015 Revenues (Line 49 * Line 50)	-$837,437	-$275,428	-$22,640	-$144,056	-$18,140	-$3,239	-$465	-$199,912	-$96,888	-$75,883	-$15	-$750	-$19

Notes:

1 **2014 October Update APCU Revenues = ($1.31)/MWh x 639,264.818 MWhs =** **$ (837,437) (Line 42, Column A)**

2 **($1.31) = $21.82 (2014 October APCU Rate) - $23.13 (2013 October APCU Rate)**

Idaho Power Company
Rate Spread Exhibit for March Forecast APCU

General Rate Case (UE 233): Marginal Cost-of-Service Study and Stipulated Revenue Spread

2011 Test Period

Line	Description	(A) TOTAL SYSTEM	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(F) GEN SRV TRANS (9-T)	(G) AREA LIGHTING (15)	(H) LG POWER PRIMARY (19-P)	(I) LG POWER TRANS (19-T)	(J) IRRIGATION SECONDARY (24-S)	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)
1	**Normalized Sales (kWh)**	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
2	**Current Revenue**	$39,873,591	$15,355,932	$1,559,400	$6,975,915	$798,102	$154,997	$112,462	$8,213,065	$3,123,393	$3,454,271	$972	$123,851	$1,231
3														
4	**Demand Related Marginal Cost**													
5	Generation - Staff Adj.	$11,049,450	$4,082,443	$268,043	$1,671,178	$207,813	$35,425	$625	$1,790,415	$1,483,718	$1,508,400	$158	$1,035	$200
6	Transmission - Staff Adj.	$12,432,118	$4,593,297	$301,584	$1,880,300	$233,817	$39,858	$703	$2,014,458	$1,669,382	$1,697,153	$177	$1,165	$225
7	Distribution	$6,945,625	$3,215,110	$181,233	$1,319,947	$100,783	$0	$5,738	$798,946	$0	$1,314,267	$161	$9,350	$89
8														
9	**Energy Related Marginal Cost**													
10	Generation	$28,547,004	$8,940,577	$802,452	$5,140,232	$649,911	$117,743	$21,383	$7,662,010	$3,097,424	$2,079,568	$570	$34,414	$722
11	Transmission - Staff Adj.	$4,144,040	$1,297,863	$116,488	$746,184	$94,345	$17,092	$3,104	$1,112,259	$449,639	$301,881	$83	$4,996	$105
12														
13	**Simple-Summed Energy-Related and Demand-Related Marginal Costs**													
14	Generation Marginal Costs - Staff Adj.	$39,596,454	$13,023,020	$1,070,495	$6,811,410	$857,724	$153,168	$22,008	$9,452,425	$4,581,142	$3,587,968	$728	$35,449	$922
15	Transmission Marginal Costs - Staff Adj.	$16,576,157	$5,891,160	$418,072	$2,626,484	$328,162	$56,950	$3,807	$3,126,717	$2,119,021	$1,999,034	$260	$6,160	$330
16														
17	**Customer Related Marginal Cost**	$2,805,903	$1,967,110	$385,570	$177,410	$6,719	$1,390	$0	$15,208	$2,535	$246,967	$228	$1,892	$873
18														
19	**Total Functionalized Revenue Requirement**													
20	Generation - Staff Adj.	$25,202,690	$8,289,003	$681,357	$4,335,384	$545,931	$97,490	$14,008	$6,016,360	$2,915,844	$2,283,701	$463	$22,563	$587
21														
22	Transmission	$4,272,366	$1,518,397	$107,755	$676,954	$84,581	$14,678	$981	$805,885	$546,160	$515,234	$67	$1,588	$85
23														
24	Distribution													
25	Demand-Related	$8,930,530	$4,133,917	$233,025	$1,697,158	$129,585	$0	$7,378	$1,027,267	$0	$1,689,855	$207	$12,022	$114
26	Customer-Related													
27	Allocated	$2,859,472	$2,004,665	$392,931	$180,797	$6,847	$1,417	$0	$15,498	$2,583	$251,682	$232	$1,928	$890
28	Direct Assignment	$419,424	$188,447	$34,356	$12,375	$69	$14	$78,778	$83	$14	$21,953	$42	$83,209	$83
29														
30	**Total: Staff-Adjusted Allocation**	$41,684,482	$16,134,429	$1,449,425	$6,902,669	$767,013	$113,599	$101,145	$7,865,094	$3,464,601	$4,762,425	$1,011	$121,310	$1,759
31	**Revenue Deficiency - Staff Adj. Allocation**	$1,810,890	$778,497	($109,975)	($73,246)	($31,089)	($41,398)	($11,317)	($347,971)	$341,208	$1,308,154	$39	($2,541)	$528
32	**% Increase Required by Staff Adj. Alloc. Approach**	4.54%	5.07%	-7.05%	-1.05%	-3.90%	-26.71%	-10.06%	-4.24%	10.92%	37.87%	4.02%	-2.05%	42.91%
33	**$ Increase Recommended per Stipulation**	$1,810,890	$862,348	$44,153	$197,517	$22,598	$0	$0	$232,545	$212,777	$235,318	$44	$3,507	$84
34	**% Increase Recommended per Stipulation**	**4.54%**	**5.62%**	**2.83%**	**2.83%**	**2.83%**	**0.00%**	**0.00%**	**2.83%**	**6.81%**	**6.81%**	**4.56%**	**2.83%**	**6.81%**
35	**Average Rate Given Stipulation ($/kWh)**	0.0641	0.0816	0.0899	0.0628	0.0544	0.0547	0.2324	0.0471	0.0450	0.0791	0.0788	0.1637	0.0805
36	**Final Revenue Allocation**	$41,684,481	$16,218,280	$1,603,553	$7,173,432	$820,700	$154,997	$112,462	$8,445,610	$3,336,170	$3,689,589	$1,016	$127,358	$1,315
37														
38	**Spread Floors and Ceilings:**													
39	No increase for those warranting a decrease greater than 8%													
40	2.83% increase for those warranting a decrease less than 8%													
41	No increase greater than one-and-one-half times the average increase													

2014 March Forecast APCU: Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures

Line	Description	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
42	2014 March Forecast APCU Cost of Service (Allocator -- Line 14)	$2,678,520	$880,948	$72,414	$460,761	$58,021	$10,361	$1,489	$639,413	$309,893	$242,710	$49	$2,398	$62
43	% Increase Required Due to APCU (Proposed) (Line 42/(Line 36)	6.43%	5.43%	4.52%	6.42%	7.07%	6.68%	1.32%	7.57%	9.29%	6.58%	4.84%	1.88%	4.74%
44	Proposed Combined Revenue Spread (Line 36 + Line 42)	$44,363,000	$17,099,228	$1,675,967	$7,634,192	$878,721	$165,358	$113,951	$9,085,024	$3,646,063	$3,932,298	$1,066	$129,756	$1,377
45	Loss-Adjusted 2011 Normalized Sales (kWh)	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
46	2014 March Forecast Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*(Line 42/Line 45))	4.120	4.430	4.058	4.033	3.843	3.658	3.076	3.568	4.179	5.203	3.815	3.082	3.820
47	**APCU Incremental Rate for 2014 March Forecast (Mills per kWh) (Line 46*(Column A:[Line 45/Line 48]))**	**4.190**	**4.679**	**4.017**	**4.054**	**3.425**	**4.216**	**3.252**	**3.721**	**3.743**	**5.528**	**5.598**	**2.704**	**2.968**
48	*Loss-Adjusted 2014-2015 Normalized Sales (kWh)*	639,264,818	188,282,848	18,025,844	113,647,734	16,942,598	2,457,786	457,839	171,834,384	82,791,791	43,907,465	8,791	886,721	21,017
49	Projected March Forecast APCU 2014-2015 Revenues (Line 47 * Line 48)	$2,678,520	$880,948	$72,414	$460,761	$58,021	$10,361	$1,489	$639,413	$309,893	$242,710	$49	$2,398	$62

Notes:

1 **2014 March Forecast APCU Revenues = $4.19/MWh x 639,264.818 MWhs = $ 2,678,520 (Line 42, Column A)**

Idaho Power/205
Witness: Scott Wright

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 279
MARCH FORECAST

Exhibit Accompanying Testimony of Scott Wright

Summary of Revenue Charge

March 21, 2014

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2014

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers	Normalized Energy (kWh)	Current Billed Revenue	Mills Per kWh	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Mills Per kWh	Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:									
1	Residential Service	1	13,586	188,282,848	$18,256,881	96.97	$139,518	$18,396,399	97.71	0.76%
2	Small General Service	7	2,484	18,025,844	$1,850,388	102.65	$11,176	$1,861,564	103.27	0.60%
3	Large General Service	9	919	133,048,118	$9,874,664	74.22	$83,583	$9,958,247	74.85	0.85%
4	Dusk to Dawn Lighting	15	0	457,839	$111,343	243.19	$260	$111,603	243.76	0.23%
5	Large Power Service	19	6	254,626,175	$14,917,986	58.59	$131,745	$15,049,731	59.11	0.88%
6	Agricultural Irrigation Service	24	1,655	43,907,465	$4,176,044	95.11	$38,726	$4,214,770	95.99	0.93%
7	Unmetered General Service	40	2	8,791	$808	91.89	$13	$821	93.35	1.59%
8	Street Lighting	41	24	886,721	$139,921	157.80	$289	$140,210	158.12	0.21%
9	Traffic Control Lighting	42	7	21,017	$1,925	91.61	$10	$1,935	92.07	0.50%
10	Total Uniform Tariffs		18,683	639,264,818	$49,329,960	77.17	$405,319	$49,735,279	77.80	0.82%
12	Total Oregon Retail Sales		18,683	639,264,818	$49,329,960	77.17	$405,319	$49,735,279	77.80	0.82%

(1) Updated April 2014 - March 2015 Test Year

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in Docket UE 279 on the following named person(s) on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below.

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DATED: March 21, 2014

Wendy McIndoo

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