McDOWELL RACKNER GIBSON PC

ALISHA TILL
503-290-3628
alisha@mrg-law.com

March 23, 2018

**VIA ELECTRONIC FILING**
Attention: Filing Center
Public Utility Commission of Oregon
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97308-1088

**Re: UE 333 - In the Matter of IDAHO POWER COMPANY'S 2018 Annual Power Cost Update**

Attention Filing Center:

Attached for filing in the above-referenced docket is an electronic copy of Idaho Power Company's March Forecast – Direct Testimony of Nicole A. Blackwell (Idaho Power/400-407). The workpapers and supporting documents for the 2018 March Forecast will be provided to Staff and CUB within five business days of the filing of the March Forecast. Please contact this office with any questions.

Sincerely,

Alisha Till

Alisha Till
Legal Assistant

Attachment

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

**UE 333**

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|---|---|
| IN THE MATTER OF IDAHO POWER COMPANY'S 2018 ANNUAL POWER COST UPDATE | ) ) ) |
| MARCH FORECAST | ) ) ) ) |

**IDAHO POWER COMPANY**

**DIRECT TESTIMONY**

**OF**

**NICOLE A. BLACKWELL**

**March 23, 2018**

**Q. Are you the same Nicole A. Blackwell who previously submitted testimony in this proceeding?**

A. Yes. I previously submitted direct and reply testimony in this proceeding regarding the October Update for the 2018 Annual Power Cost Update ("APCU"). The 2018 October Update is Idaho Power Company's ("Idaho Power" or "Company") estimate of what "normalized" power supply expenses will be for the upcoming APCU test period of April 2018 through March 2019.

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

A. The Company filed the 2018 October Update on October 31, 2017, and Public Utility Commission of Oregon ("Commission") Staff ("Staff") and the Oregon Citizens' Utility Board ("CUB") reviewed the filing. Several rounds of discovery requests have been served on the Company since the initial filing. The parties held an initial workshop on January 23, 2018, to discuss the 2018 October Update filing.

On February 12, 2018, Staff filed opening testimony and CUB indicated that it would not be filing opening testimony. On February 20, 2018, Idaho Power and Staff participated in a settlement conference. Although settlement was not reached, from the Company's perspective, the conference was useful to allow it to better understand and respond to the Staff's position and concerns. On March 1, 2018, the Company filed reply testimony in response to issues raised by Staff in opening testimony.

**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.[1] As mentioned previously, the Company filed the first part of the APCU, the October Update, on October 31, 2017. The initial October Update filing proposed a revenue increase of

[1] *Re Idaho Power Company's Application for Authority to Implement a Power Cost Adjustment Mechanism*, Docket No. UE 195, Order No. 08-238 (Apr. 28, 2008).

approximately $0.36 million, or 0.65 percent. If the March Forecast and October Update are approved as filed, the 2018 composite APCU (both the October Update and March Forecast components) will result in a revenue decrease of $0.22 million or a 0.39 percent decrease, to become effective June 1, 2018.

**Q. How is your testimony organized?**

A. My testimony begins by describing the filing requirements associated with the March Forecast and the differences between the October Update and the March Forecast. Next, my testimony describes the required updates to the AURORAxmp Electric Market Model ("AURORA"). I then present and discuss the forecast of total net power supply expenses ("NPSE") for the 2018 March Forecast and how it compares to last year's 2017 March Forecast. My testimony concludes with the quantification of the projected revenue requirement decrease and the proposed rate implementation to allocate the revenue decrease to customers.

**Q. Have you prepared exhibits for this proceeding?**

A. Yes, I am sponsoring the following exhibits:

1. Exhibit 401, Forward Price Curves used for re-pricing purchased power and surplus sales.
2. Exhibit 402, determination of expected NPSE for the 2018 March Forecast.
3. Exhibit 403, October Update and March Forecast combined rate calculation.
4. Exhibit 404, Year-Over-Year Differences in Modeled NPSE.
5. Exhibit 405, Energy Imbalance Market Costs & Benefits.
6. Exhibit 406, Revenue Spread.
7. Exhibit 407, Calculation of Revenue Impact.

## March Forecast Overview

**Q. What is the March Forecast?**

A. The March Forecast is the Company's quantification of the "expected" 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 was calculated by simulating 89 water year conditions in the AURORA model and then averaging the results of all 89 resulting NPSE scenarios 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 current reservoir levels and the most recent water supply forecast from the Northwest River Forecast Center ("NWRFC"). 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.

## AURORA Model Inputs

**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, as described in Order No. 08-238, are 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 current reservoir levels and the most recent water supply forecast from the NWRFC;

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

h. Forward price curve;

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

j. The Oregon state allocation factor.

**Q. How do the modeling variables, as described in Order No. 08-238, compare between the 2018 March Forecast and those used to develop the 2018 October Update?**

A. All of the modeling variables described in Order No. 08-238 were reviewed for accuracy, and updated where appropriate, in the preparation of the proposed March Forecast. For the April 2018 through March 2019 test period, the following variables changed since the October APCU was prepared: (1) fuel prices and transportation costs, (2) planned outages and forced outage rates, (3) heat rates, (4) forecast of hydro generation from stream flow conditions using the most recent water supply forecast from the NWRFC and current reservoir levels, (5) known power purchases and surplus sales made in compliance with the Company's Energy Risk Management Policy ("ERMP"), (6) forward price curve, and (7) PURPA contract expenses.

*<u>Fuel Expense</u>*

**Q. How frequently are the Company's fuel cost forecasts updated?**

A. The coal and gas price forecasts are refreshed monthly for operational planning purposes. When the October Update was prepared, information from the September 2017 Operations Plan was used. The March Forecast determination of NPSE includes the Company's most current coal and gas price forecasts.

**Q. How do AURORA-modeled coal fuel expense and coal-fired generation for the March Forecast compare to the October Update results?**

A. Total coal fuel expense included in the 2018 March Forecast is $58.8 million, compared to $77.6 million in the 2018 October Update, a decrease of 24 percent.

Coal-fired generation also decreased as compared to the October Update, from 2.1 million megawatt-hours ("MWh") to 1.6 million MWh, or approximately 24 percent.

**Q. How do the decrease in coal fuel expense and coal-fired generation impact the cost of coal production on a per-unit basis?**

A. The average cost of coal production on a per-unit basis for the March Forecast is $37.40 per MWh, compared to $37.29 per MWh for the October Update. At the plant level, the per-unit cost of production increased 4 percent at the Jim Bridger plant ("Bridger"), decreased 12 percent at the Boardman plant ("Boardman"), and increased 4 percent at the North Valmy ("Valmy") plant.

**Q. What factors drove the changes in the per-unit cost of production at the Company's coal plants since the October Update was filed?**

A. The per-unit variable cost of production at Boardman decreased between the October Update and the March Forecast primarily due to lower coal costs, on a dollar per MMBtu basis. The dollar per MMBtu coal costs for Boardman decreased 12 percent between the October Update and March Forecast due to decreased coal transport costs, volumes, and coal costs as of the end of 2017. As a result of the decrease in coal costs, the AURORA-modeled dispatch of Boardman increased between the October Update and March Forecast. The increase in production volumes and lower coal costs resulted in a decrease in the per-unit cost of production.

While the coal costs, on a dollar per MMBtu basis, at Bridger and Valmy remained relatively unchanged between the October Update and the March Forecast, the per-unit cost of production increased as a result of operating costs being spread over lower production volumes. The lower production volumes are primarily due to the continued decrease in natural gas prices. Lower natural gas prices impact the production volumes at the coal-fired plants because it shifts the dispatch of coal-fired generating units to natural gas generating units. Due to low-cost natural gas, generation at Bridger and Valmy is being displaced and the ability to economically dispatch the plants for surplus sales is reduced.

**Q. Did the Company update its forecast of total Oil, Handling, and Administrative and General ("OHAG") expenses per the terms of the 2016 and 2017 APCU settlement stipulations?**

A. Yes. Per the terms of the 2016 APCU settlement stipulation,[2] for the March Forecast, the Company included within the AURORA model the per-MWh OHAG expense driven by Idaho Power's dispatch of each coal plant. The Company separately accounted for its proportional share of the total OHAG expenses incurred at each of the coal plants.

Per the terms of the 2017 APCU settlement stipulation ("2017 Stipulation"),[3] the Company is to annually update its proportional share of total forecast OHAG expense incurred at each of the coal plants as part of the March Forecast filing. The Company's OHAG forecast is calculated based on a three-year historical average of actual OHAG costs, with a growth (reduction) rate equal to the five-year historical average growth (reduction) rate. For the 2018 March Forecast, Idaho Power updated the OHAG forecast using the 2015 – 2017 historical average of actual OHAG costs, with a growth rate equal to the 2013 – 2017 historical average growth rate. The forecast of total OHAG expenses for Bridger, Boardman, and Valmy are displayed on lines 6, 12, and 18 of Exhibit 402, respectively.

**Q. Does Idaho Power's 2018 March Forecast account for revenues received from or expenses paid to NV Energy (its ownership partner in the Valmy plant) for**

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[2] *In the Matter of Idaho Power Company's 2016 Annual Power Cost Update*, Docket No. UE 301, Stipulation/7 (May 11, 2016).

[3] *In the Matter of Idaho Power Company's 2017 Annual Power Cost Update*, Docket No. UE 314, Stipulation/7 (April 28, 2017).

**usage of the Company's unused capacity or the Company's usage of NV Energy's unused capacity?**

A. Yes. Per the terms of the 2017 Stipulation,[4] Idaho Power agreed to include the three-year historical average of actual net balances associated with ownership partner use of unused capacity at Valmy as an offset or expense to total NPSE. The Company is to update the three-year historical average as part of the March Forecast. For the 2018 March Forecast, the 2015 – 2017 historical average net revenue paid to Idaho Power is $48,368 on a system-wide basis, associated with NV Energy's dispatch of Idaho Power's unused capacity at Valmy. As shown on line 19 of Exhibit 402, this amount has been reflected as an offset to NPSE for Valmy for the 2018 March Forecast.

**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 $3.18 per MMBtu, while the gas price forecast used for the March Forecast for Henry Hub was $3.12 per MMBtu, a decrease of $0.06 per MMBtu.

**Q. How is the Henry Hub gas price forecast 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 market prices are determined by applying an adjustment factor to the Henry Hub price. For example, a Henry Hub gas price of $3.12 per MMBtu applied to a Sumas basis of a negative $0.71 per MMBtu equals a Sumas gas price of $2.41 per MMBtu ($3.12 + ($0.71) = $2.41). The Company develops a separate gas price for its natural gas units also based upon the Henry Hub gas price forecast.

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[4] *Id.* at 3.

*PURPA Expense*

**Q. Please describe any changes to PURPA generation since the October Update.**

A. The October Update included 332 average megawatts ("aMW") of available PURPA generation, whereas the PURPA generation included in the March Forecast is 331 aMW, a decrease of 1 aMW since the October Update.

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

A. Total PURPA expense included in the March Forecast is $211.2 million compared to the $217.2 million included in the October Update, a decrease of $6.0 million or 3 percent.

*Normalized Load*

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

A. There was no change in the forecast of normalized load between the October Update and the March Forecast. The forecast of normalized load used for the October Update and March Forecast was 1,854 aMW. Although there was not a change in system normalized load, there was a reallocation of normalized load and billed sales by jurisdiction between the October Update and March Forecast, which will be discussed later in my testimony.

*Hydro Forecast*

**Q. What was the date of the water supply forecast from the NWRFC 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 NWRFC's March 5, 2018, forecast. The March 5, 2018, forecast has expected inflows into Brownlee Reservoir for April through July of 5.27 million acre-feet ("MAF"), or 96 percent of the 30-year (1981-2010) average volume of 5.47 MAF.

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

A. The NWRFC's forecast used in last year's March Forecast was 7.58 MAF compared to this year's forecast of 5.27 MAF, reflecting a 30 percent decrease in expected inflows into Brownlee Reservoir for April through July. Expected inflows into Brownlee Reservoir were higher for last year's March Forecast as a result of better snowpack conditions, which provide for sustained runoff and increased hydro generation during the spring and summer months.

**Q. How does the decrease in expected inflows impact this year's hydro generation forecast compared to last year's forecast?**

A. The hydro generation forecasted for this year's March Forecast is 8.5 million MWh compared to 8.7 million MWh in last year's March Forecast, a 2 percent decrease.

**Q. Please explain why the decrease in forecast hydro generation is not proportional to the decrease in forecast inflows at Brownlee as compared to last year.**

A. Although forecast inflows into Brownlee Reservoir are 30 percent lower for the months of April through July as compared to last year, total forecast generation is only 2 percent lower than last year. In 2017, high inflows into Brownlee Reservoir occurred during the spring months. Concurrent with high inflows, Brownlee Reservoir was required to meet flood risk management elevation targets in April, then undergo refill coordinated with the U.S. Army Corps of Engineers. The result was that flows in excess of power plant capacity were spilled through the Hells Canyon Complex. Therefore, only a portion of the higher inflows last year were available for hydro generation. This year, inflows and flood control targets are forecast to keep flows generally within power plant capacity through the spring, resulting in a similar generation estimate as compared to last year.

**Q. How does the hydro generation forecast compare to the normalized scenario used for the October Update?**

A. The hydro generation forecasted under the normalized scenario (89 water years) for the October Update was 8.63 million MWh. The hydro generation forecasted under this year's March Forecast is 8.51 million MWh, a decrease of 0.12 million MWh or 13.7 aMW (0.12 million MWh ÷ 8,760 hours = 13.7 aMW) as compared to the October Update, which suggests that the expected hydro generation for the March Forecast is near normal.

*Known Power Purchases and Surplus Sales*

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

A. Yes. The Company includes known power purchases and surplus sales resulting from the Company's ERMP and incorporates those amounts as Net Hedges on Exhibit 402, lines 42 and 43, as directed by Order No. 08-238. Known power purchases and surplus sales are not included in the October Update of the APCU.

*Re-Pricing Based on a Forward Price Curve*

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

A. Exhibit 401 shows the March 12, 2018, Mid-C Heavy Load (HL) and Light Load (LL) forward price curve for the April 2018 through March 2019 test period the Company used for the March Forecast, as directed by Order No. 08-238.

*Other*

**Q. What other AURORA inputs have changed since the October Update?**

A. The Company updated the planned outage schedule, forced outage rates, and heat rates for its thermal plants.

**2018 Forecast NPSE**

**Q. Have you prepared an exhibit that summarizes the total NPSE for the March Forecast?**

A. Yes. Exhibit 402 shows the results of the AURORA modeling determination of forecast NPSE, as well as the re-pricing of market purchases and surplus sales, and total PURPA expense for the April 2018 through March 2019 test year.

**Q. What is the Company's March Forecast of NPSE as a result of the changes described above?**

A. Exhibit 402 shows the results of a single water condition for the April 2018 through March 2019 test period, with updated fuel prices, normalized load, updated stream flow conditions, updated power purchases, and surplus sales from the Company's ERMP (Net Hedges), market purchased power and surplus sales re-priced, and updated PURPA contract expenses. The March Forecast of NPSE without PURPA expenses is $176.7 million. When PURPA expenses of $211.2 million are included, the total NPSE for the March Forecast is $387.9 million.

**Q. How does the 2018 March Forecast of NPSE compare to last year's March Forecast of NPSE?**

A. The 2018 March Forecast of NPSE without PURPA expense is $176.7 million, or $0.3 million less than the 2017 March Forecast of NPSE without PURPA expenses of $177.0 million. With PURPA expenses included, the 2018 March Forecast of NPSE is $387.9 million, or $2.1 million more than the 2017 March Forecast of NPSE of $385.8 million.

**Q. How does the modeled generation in the 2018 March Forecast compare to last year's March Forecast?**

A. A high level analysis of the results suggests that lower priced natural gas generation is displacing coal generation and higher priced market power purchases. At the same time, the reduction in forecast hydro generation and decreased market sales prices have reduced the Company's ability to make economic off-system sales. PURPA generation remained relatively unchanged compared to last year's March Forecast. Exhibit 404 compares the AURORA-developed results, the re-pricing of purchased power and surplus sales, and the differences between the 2018 March Forecast and 2017 March Forecast.

**Q. What are some of the differences in resource dispatch as shown on Exhibit 404?**

A. Column H of Exhibit 404 shows the following: a decrease in coal expenses of $9.3 million associated with a 0.36 million MWh reduction in generation; an increase in natural gas expense of $12.4 million associated with an increase of 0.75 million MWh in generation; a decrease in purchased power expenses of $6.9 million associated with a decrease of 0.30 million MWh; an increase in PURPA expenses of $2.4 million associated with a decrease of 0.02 million MWh; and finally, a decrease in surplus sales revenue of $3.6 million associated with a decrease of 0.46 million MWh.

**Q. How does expected generation change from the 2017 March Forecast to the 2018 March Forecast?**

A. To illustrate the changes in generation, Columns D (2017) and F (2018) of Exhibit 404 calculate the percentage of generation compared to total system load. For the 2018 March Forecast, hydro generation decreased from 55 percent to 52 percent; coal generation decreased from 12 percent to 10 percent; natural gas generation increased from 16 percent to 21 percent; purchased power, and Power Purchase Agreements ("PPA") decreased from 9 percent to 7 percent; PURPA generation remained unchanged at 18 percent; and lastly, surplus sales decreased from 11 percent to 8 percent. This comparison between resource type and total system load shows that natural gas resources are displacing coal resources and that reduced hydro generation and low market sales prices are contributing to the decrease in surplus sales.

**Q. Are the relative changes in expenses between resource types consistent with the changes in output?**

A. Yes. The relative changes in expenses between resource types are consistent with the changes in output. The changes in expenses shown in Columns D (2017) and F (2018) of Exhibit 404 are as follows: Coal decreased from 18 percent to 15 percent of total expense; natural gas increased from 17 percent to 20 percent; purchase power, and PPA decreased from 17 percent to 15 percent; PURPA expense remained at 54 percent; and surplus sales revenue decreased from negative 5 percent to negative 4 percent. Exhibit 404 demonstrates that the majority of movement in expenses is related to coal, natural gas, and market purchased power.

**Q. Please summarize the factors driving the change in NPSE as compared to last year's March Forecast.**

A. The average per-unit cost of natural gas generation is $22.97 per MWh, and specifically $17.36 per MWh for the Langley Gulch plant, whereas the average modeled per-unit cost at the Company's coal plants is $37.40 per MWh, and the average AURORA-modeled market purchase price (before re-pricing) is $31.68 per MWh. As a result, less-expensive natural gas dispatch increased, offsetting more-expensive coal generation and higher priced market power purchases.

As a result of the reduction in hydro generation and decreased market sales prices, the Company's ability to make economic off-system sales decreased, which had an upward impact on NPSE as compared to last year. The average AURORA-modeled market sales prices (before re-pricing) is $20.16 per MWh, as compared to $22.65 for the 2017 March Forecast. The other factor diving the increase in NPSE as compared to last year's March Forecast is the $2.4 million increase in PURPA expense.

**Q. How does the re-pricing of purchased power and surplus sales change purchased power expenses and surplus sales revenues as modeled by AURORA?**

A. As shown in Columns I and J of Exhibit 404, for this year's March Forecast, re-pricing of market purchases and sales results in a net increase in NPSE of $3.7 million. The re-pricing of purchased power decreased the average market purchase price of $31.68 per MWh (as modeled in AURORA) to $23.15 per MWh, resulting in a $5.2 million decrease in NPSE. The re-pricing of surplus sales decreased the average market sales price of $20.16 per MWh (as modeled in AURORA) to $13.22 per MWh, resulting in a decrease in surplus sales revenue of $8.9 million.

*Energy Imbalance Market ("EIM") Costs and Benefits*

**Q. Did the Company update the estimated EIM costs and benefits to be included in the 2018 APCU?**

A. Yes. The Company updated the annual revenue requirement associated with the EIM-related costs to be included in the 2018 APCU. On an Oregon-allocated basis, the revenue requirement associated with EIM costs is $113,268 which is $31,748 more than the estimate included in the October Update. The revenue requirement calculation includes updated amounts based on more recent cost estimates and revised tax rates associated with 2017 tax reform.

As discussed in my 2018 October Update testimony, the Company proposes to set EIM benefits equal to EIM costs for the first year of participation due to the uncertainty surrounding the level of benefits that will be achieved.[5] Accordingly, the

[5] *In the Matter of Idaho Power Company's 2018 Annual Power Cost Update,* Docket No. UE 333, Idaho Power/100, Blackwell/14, lines 15 - 18 (October 31, 2017).

Company has updated the EIM benefits to be included in the 2018 APCU to $113,268, resulting in a net zero impact to NPSE and customer rates. This proposal aligns with the Commission approved treatment related to EIM cost recovery for PacifiCorp[6] and Portland General Electric[7] in their first year of EIM participation. Exhibit 405 provides the 2018 calendar year revenue requirement computation, as well as the benefits included in the 2018 APCU.

*Per-Unit Cost Calculation and Quantification of the Revenue Requirement Impact*

**Q. What is the March Forecast unit cost per MWh for this filing?**

A. Exhibit 402 shows the normalized annual sales at the customer level for the April 2018 through March 2019 test period of 14,962,866 MWh (line 47). Based upon test period sales, the cost per-unit for the March Forecast is $25.92 per MWh ($387.9 million / 14.963 million MWh = $25.92 per MWh) (lines 46, 47, and 49).

**Q. How does this year's March Forecast unit cost per MWh compare to last year's March Forecast unit cost per MWh?**

A. The 2017 March Forecast unit cost per MWh was $26.31 per MWh ($385.8 million / 14.661 million MWh = $26.31 per MWh), compared to this year's March Forecast unit cost of $25.92 per MWh. Although the 2018 March Forecast of NPSE increased approximately 1 percent over last year's March Forecast of NPSE, forecast system sales increased to a larger degree, approximately 2 percent, over the same time period. As a result of sales increasing at a higher rate than NPSE, the March Forecast unit cost per MWh decreased as compared to last year.

**Q. Please describe the calculation necessary to determine the March Forecast rate.**

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[6] *In the Matter of PacifiCorp, dba Pacific Power, 2015 Transmission Adjustment Mechanism*, Docket No. UE 287, Settling Parties/100, Dickman, Ordonez, Garcia, Jenks & Mullins/8 (August 14, 2014).

[7] *In the Matter of Portland General Electric Company, 2017 Annual Power Cost Update Tariff (Schedule 125)*, Docket No. UE 308, UE 308/PGE/400, Niman – Peschka – Hager/20 (April 1, 2016).

A. Exhibit 403 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 unit cost of $26.54 per MWh. Lines 4-6 show the calculation for the March Forecast unit cost of $25.92 per MWh. Line 7 reflects the March Forecast unit cost minus the October Update unit cost multiplied by the March Forecast 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 calculate the March Forecast rate of negative $0.59 per MWh.

**Q. How does the negative $0.59 per MWh compare to the March Forecast rate that resulted from last year's computation?**

A. The March Forecast rate for last year's April 2017 through March 2018 test period was $0.24 per MWh, as compared to this year's April 2018 through March 2019 test period rate of negative $0.59 per MWh, a decrease of $0.83 per MWh.

**Q If NPSE is increasing as compared to last year's March's Forecast, why is the March Forecast rate a decrease from last year?**

A. As described above, the March Forecast rate is based on 95 percent of the change in NPSE between the October Update and the March Forecast, as shown on line 7 of Exhibit 403. For this year's March Forecast, the allowed difference in the normal expectation of NPSE as determined by the October Update and the expected NPSE based on the March Forecast is negative $8.8 million. For last year's March Forecast, the allowed difference in the normal expectation of NPSE as determined by the October Update and the expected NPSE based on the March Forecast was $3.5 million. Although total forecast NPSE for this year's March Forecast is a slight increase over last year, the difference in NPSE between the October Update and March Forecast is a decrease, resulting in a negative March Forecast rate. In other words, this year's March Forecast of expected NPSE is below the average NPSE determined in the October Update.

**Q. How is the revenue requirement for the March Forecast calculated using the March Forecast rate unit cost of negative $0.59 per MWh?**

A. The revenue requirement for the March Forecast is calculated by multiplying the March Forecast rate of negative $0.59 per MWh by the loss-adjusted Oregon jurisdictional sales for the April 2018 through March 2019 test period of 694,276.451 MWh, resulting in a revenue requirement decrease of $0.41 million, as shown on page 2 of Exhibit 406, line 1. Revenues collected through the current March Forecast rate of $0.24 per MWh, are approximately $0.17 million. As such, the proposed 2018 March Forecast rate of negative $0.59 per MWh will result in a revenue requirement decrease of $0.58 million compared to what is currently included in Oregon customers' rates.

## Rate Implementation

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

A. The Company proposes to allocate the revenue requirement decrease associated with the 2018 March Forecast according to the revenue spread methodology approved by the 2017 Stipulation.[8] The Stipulation established a revenue spread methodology whereby the revenue requirement is allocated to individual customer classes on the basis of normalized jurisdictional forecasted sales at the generation level for the test period. The proposed revenue spread resulting from the application of the stipulated methodology is shown on Exhibit 406.

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

[8] *Id.* at 3.

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. The practice of updating the loss-adjusted sales for the October Update revenue spread is consistent with the method applied in the last six APCU filings in Docket Nos. UE 242, UE 257, UE 279, UE 293, UE 301, and UE 314. The April 2018 through March 2019 loss-adjusted sales for the October Update were 699,655.310 MWh, whereas the loss-adjusted sales for the March Forecast are 694,276.451, a decrease of 5,378.859 MWh. The change in the loss-adjusted sales decreases the October Update revenue requirement from $360,109 to $357,204, a decrease of $2,905. Exhibit 406 also contains the revised October Update revenue spread.

**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. Exhibit 407 provides a summary of the revenue change resulting from this year's combined October Update and March Forecast as compared to current revenue. As can be seen on line 11 of Exhibit 407, the overall revenue impact of this year's combined October Update and March Forecast is a decrease of $0.22 million or 0.39 percent overall. The $0.22 million decrease reflects an increase of $0.36 million in base rate revenues associated with the October Update, and a $0.58 million decrease in Schedule 55 revenues associated with the March Forecast, as compared to what is currently included in Oregon customers' rates related to the 2017 APCU.

**Q. Does this conclude your testimony?**

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 333
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

March 12, 2018, Mid-Columbia Price Curve for April 2018 – March 2019

March 23, 2018

**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 | **3/12/2018** | **Apr-18** | **May-18** | **Jun-18** | **Jul-18** | **Aug-18** | **Sep-18** | **Oct-18** | **Nov-18** | **Dec-18** | **Jan-19** | **Feb-19** | **Mar-19** |
| 2 | **mc HL** | 16.00 | 12.45 | 13.75 | 27.00 | 34.00 | 28.25 | 23.65 | 21.85 | 29.10 | 27.40 | 23.45 | 19.00 |
| 3 | **mc LL** | 11.10 | 3.95 | 3.15 | 14.15 | 22.75 | 22.00 | 20.30 | 18.75 | 24.00 | 21.80 | 20.10 | 15.90 |
| | | | | | | | | | | | | | |
| 4 | **Reallocated Prices** | **Apr-18** | **May-18** | **Jun-18** | **Jul-18** | **Aug-18** | **Sep-18** | **Oct-18** | **Nov-18** | **Dec-18** | **Jan-19** | **Feb-19** | **Mar-19** |
| 5 | **HL PP** | | | | | | | | | | | | |
| 6 | 103.9% | 16.62 | 12.94 | 14.29 | 28.05 | 35.33 | 29.35 | 24.57 | 22.70 | 30.23 | 28.47 | 24.36 | 19.74 |
| 7 | **LL PP** | | | | | | | | | | | | |
| 8 | 107.1% | 11.89 | 4.23 | 3.37 | 15.15 | 24.37 | 23.56 | 21.74 | 20.08 | 25.70 | 23.35 | 21.53 | 17.03 |
| 9 | **HL SS** | | | | | | | | | | | | |
| 10 | 96.4% | 15.42 | 12.00 | 13.26 | 26.03 | 32.78 | 27.23 | 22.80 | 21.06 | 28.05 | 26.41 | 22.61 | 18.32 |
| 11 | **LL SS** | | | | | | | | | | | | |
| 12 | 93.4% | 10.37 | 3.69 | 2.94 | 13.22 | 21.25 | 20.55 | 18.96 | 17.51 | 22.42 | 20.36 | 18.77 | 14.85 |

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 333
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

Power Supply Costs for April 1, 2018 – March 31, 2019

March 23, 2018

**IPCO POWER SUPPLY EXPENSES FOR APRIL 1, 2018 -- MARCH 31, 2019 (One Hydro Condition)**
**Repriced Using UE 195 Settlement Methodology - 2018 March Forecast**

| Line No. | | April | May | June | July | August | September | October | November | December | January | February | March | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Hydroelectric Generation (MWh) | 1,150,817.5 | 1,080,698.5 | 959,452.5 | 663,106.1 | 538,915.8 | 363,058.2 | 473,489.4 | 394,576.0 | 585,260.4 | 687,487.2 | 733,315.3 | 881,348.2 | 8,511,525.1 |
| | Bridger | | | | | | | | | | | | | |
| 2 | Energy (MWh) | - | - | 17.5 | 175,133.5 | 202,388.7 | 121,931.4 | 30,302.3 | 109,444.3 | 133,561.8 | 70,301.0 | 32,994.4 | - | 876,075.0 |
| 3 | AURORA Modeled Expense ($ x 1000) | $ - | $ - | $ 0.7 | $ 6,270.6 | $ 7,223.3 | $ 4,391.5 | $ 1,139.5 | $ 4,119.1 | $ 4,837.2 | $ 2,560.4 | $ 1,223.8 | $ - | $ 31,766.2 |
| 4 | AURORA Modeled Handling Expense ($ x 1000) | $ - | $ - | $ 0.0 | $ 28.0 | $ 32.4 | $ 19.5 | $ 4.8 | $ 17.5 | $ 21.4 | $ 11.2 | $ 5.3 | $ - | $ 140.2 |
| 5 | AURORA Expense less Modeled Handling Expense ($ x 1000) | $ - | $ - | $ 0.7 | $ 6,242.6 | $ 7,190.9 | $ 4,372.0 | $ 1,134.7 | $ 4,101.6 | $ 4,815.8 | $ 2,549.1 | $ 1,218.6 | $ - | $ 31,626.0 |
| 6 | IPC Share of OHAG Expense ($ x 1000) | $ 209.9 | $ 209.9 | $ 209.9 | $ 209.9 | $ 209.9 | $ 209.9 | $ 209.9 | $ 209.9 | $ 209.9 | $ 209.9 | $ 209.9 | $ 209.9 | $ 2,518.9 |
| 7 | Total Expense ($ x 1000) | $ 209.9 | $ 209.9 | $ 210.6 | $ 6,452.5 | $ 7,400.8 | $ 4,581.9 | $ 1,344.6 | $ 4,311.5 | $ 5,025.8 | $ 2,759.1 | $ 1,428.5 | $ 209.9 | $ 34,144.9 |
| | Boardman | | | | | | | | | | | | | |
| 8 | Energy (MWh) | 4,370.0 | 1,538.6 | 13,239.5 | 38,860.9 | 40,137.8 | 35,873.1 | 27,709.2 | 28,824.8 | 34,253.2 | 33,377.0 | 21,645.1 | 11,317.5 | 291,146.8 |
| 9 | AURORA Modeled Expense ($ x 1000) | $ 126.6 | $ 45.2 | $ 342.2 | $ 977.4 | $ 1,009.6 | $ 903.5 | $ 702.2 | $ 729.8 | $ 862.3 | $ 878.7 | $ 578.2 | $ 315.5 | $ 7,471.2 |
| 10 | AURORA Modeled Handling Expense ($ x 1000) | $ 0.2 | $ 0.1 | $ 0.7 | $ 1.9 | $ 2.0 | $ 1.8 | $ 1.4 | $ 1.4 | $ 1.7 | $ 1.7 | $ 1.1 | $ 0.6 | $ 14.6 |
| 11 | AURORA Expense less Modeled Handling Expense ($ x 1000) | $ 126.3 | $ 45.1 | $ 341.5 | $ 975.5 | $ 1,007.6 | $ 901.7 | $ 700.8 | $ 728.4 | $ 860.6 | $ 877.0 | $ 577.1 | $ 314.9 | $ 7,456.6 |
| 12 | IPC Share of OHAG Expense ($ x 1000) | $ 17.7 | $ 17.7 | $ 17.7 | $ 17.7 | $ 17.7 | $ 17.7 | $ 17.7 | $ 17.7 | $ 17.7 | $ 17.7 | $ 17.7 | $ 17.7 | $ 212.8 |
| 13 | Total Expense ($ x 1000) | $ 144.1 | $ 62.8 | $ 359.2 | $ 993.2 | $ 1,025.3 | $ 919.4 | $ 718.5 | $ 746.1 | $ 878.3 | $ 894.8 | $ 594.9 | $ 332.7 | $ 7,669.4 |
| | Valmy | | | | | | | | | | | | | |
| 14 | Energy (MWh) | - | - | 1,390.9 | 57,267.7 | 75,555.7 | 53,408.0 | 28,688.2 | 41,356.0 | 72,073.8 | 46,863.0 | 24,568.1 | 2,966.6 | 404,137.8 |
| 15 | AURORA Modeled Expense ($ x 1000) | $ - | $ - | $ 45.0 | $ 1,897.0 | $ 2,474.8 | $ 1,774.3 | $ 1,005.1 | $ 1,377.8 | $ 2,346.9 | $ 1,569.1 | $ 856.8 | $ 107.8 | $ 13,454.7 |
| 16 | AURORA Modeled Handling Expense ($ x 1000) | $ - | $ - | $ 1.3 | $ 52.7 | $ 69.5 | $ 49.1 | $ 26.4 | $ 38.0 | $ 66.3 | $ 43.1 | $ 22.6 | $ 2.7 | $ 371.8 |
| 17 | AURORA Expense less Modeled Handling Expense ($ x 1000) | $ - | $ - | $ 43.8 | $ 1,844.3 | $ 2,405.3 | $ 1,725.2 | $ 978.7 | $ 1,339.8 | $ 2,280.6 | $ 1,526.0 | $ 834.2 | $ 105.1 | $ 13,082.9 |
| 18 | IPC Share of OHAG Expense ($ x 1000) | $ 326.9 | $ 326.9 | $ 326.9 | $ 326.9 | $ 326.9 | $ 326.9 | $ 326.9 | $ 326.9 | $ 326.9 | $ 326.9 | $ 326.9 | $ 326.9 | $ 3,923.3 |
| 19 | Usage Charges Paid to IPC ($ x 1000) | | | | | | | | | | | | | $ 48.4 |
| 20 | Total Expense ($ x 1000) | $ 326.9 | $ 326.9 | $ 370.7 | $ 2,171.3 | $ 2,732.2 | $ 2,052.1 | $ 1,305.6 | $ 1,666.7 | $ 2,607.6 | $ 1,852.9 | $ 1,161.1 | $ 432.1 | $ 16,957.8 |
| | Langley Gulch | | | | | | | | | | | | | |
| 21 | Energy (MWh) | 173,570.7 | 195,570.4 | 187,024.9 | 199,049.8 | 199,049.8 | 194,645.3 | 197,287.8 | 191,909.1 | 211,800.9 | 209,820.3 | 182,253.5 | 190,095.4 | 2,332,077.8 |
| 22 | Expense ($ x 1000) | $ 2,567.2 | $ 2,868.1 | $ 2,855.7 | $ 2,963.2 | $ 3,106.0 | $ 3,277.7 | $ 3,209.6 | $ 3,671.2 | $ 4,744.3 | $ 4,340.1 | $ 3,569.7 | $ 3,312.3 | $ 40,485.0 |
| | Danskin | | | | | | | | | | | | | |
| 23 | Energy (MWh) | 196.0 | 1,494.0 | 38,769.6 | 156,860.7 | 159,794.8 | 107,295.3 | 84,652.9 | 47,472.4 | 7,442.5 | 6,072.2 | 6,466.4 | 4,809.2 | 621,326.0 |
| 24 | Expense ($ x 1000) | $ 4.8 | $ 36.5 | $ 993.2 | $ 4,097.1 | $ 4,372.0 | $ 3,046.4 | $ 2,299.9 | $ 1,490.2 | $ 270.8 | $ 204.8 | $ 207.4 | $ 138.1 | $ 17,161.2 |
| | Bennett Mountain | | | | | | | | | | | | | |
| 25 | Energy (MWh) | - | 153.6 | 16,602.7 | 104,230.7 | 110,567.8 | 80,379.1 | 49,221.8 | 23,715.3 | 3,081.8 | 597.4 | 3,162.9 | 1,899.1 | 393,612.2 |
| 26 | Expense ($ x 1000) | $ - | $ 3.8 | $ 429.7 | $ 2,639.6 | $ 2,925.4 | $ 2,278.3 | $ 1,349.5 | $ 754.6 | $ 113.8 | $ 20.5 | $ 103.1 | $ 55.5 | $ 10,673.8 |
| 27 | Fixed Capacity Charge - Gas Transportation ($ x 1000) | $ 696.5 | $ 719.3 | $ 723.5 | $ 747.2 | $ 747.2 | $ 723.5 | $ 714.8 | $ 692.2 | $ 714.8 | $ 713.5 | $ 645.6 | $ 713.5 | $ 8,551.4 |
| | Purchased Power (Excluding PURPA) | | | | | | | | | | | | | |
| 28 | Market Energy (MWh) | - | - | 57,722.5 | 36,786.8 | 53,986.1 | 63,362.4 | 16,868.3 | 99,872.5 | 105,382.0 | 135,894.1 | 36,538.6 | 5,433.8 | 611,847.0 |
| 29 | Elkhorn Wind Energy (MWh) | 26,520.8 | 25,525.8 | 25,150.8 | 26,303.4 | 23,209.4 | 21,015.4 | 23,409.4 | 30,182.4 | 27,577.6 | 24,216.8 | 24,037.6 | 26,788.0 | 303,937.1 |
| 30 | Neal Hot Springs Energy (MWh) | 14,315.7 | 11,493.2 | 10,545.1 | 8,775.0 | 9,512.8 | 11,769.1 | 12,824.2 | 16,268.0 | 18,722.7 | 17,961.6 | 16,403.0 | 16,710.6 | 165,300.9 |
| 31 | Raft River Geothermal Energy (MWh) | 6,436.3 | 5,156.4 | 5,315.6 | 5,768.1 | 5,254.4 | 5,967.1 | 6,353.2 | 6,873.5 | 7,236.1 | 7,122.3 | 6,304.8 | 6,671.6 | 74,459.3 |
| 32 | Total Energy Excl. PURPA (MWh) | 47,272.8 | 42,175.4 | 98,733.9 | 77,633.2 | 91,962.7 | 102,114.0 | 59,455.0 | 153,196.3 | 158,918.3 | 185,194.8 | 83,283.9 | 55,604.0 | 1,155,544.3 |
| 33 | Market Expense ($ x 1000) | $ - | $ - | $ 463.7 | $ 786.2 | $ 1,436.7 | $ 1,682.2 | $ 392.5 | $ 2,150.3 | $ 2,919.5 | $ 3,432.2 | $ 806.9 | $ 93.0 | $ 14,163.2 |
| 34 | Elkhorn Wind Expense ($ x 1000) | $ 1,217.0 | $ 1,171.4 | $ 1,570.2 | $ 1,970.4 | $ 1,738.6 | $ 1,312.0 | $ 1,461.4 | $ 2,261.0 | $ 2,065.8 | $ 1,557.1 | $ 1,545.6 | $ 1,266.0 | $ 19,136.6 |
| 35 | Neal Hot Springs Expense ($ x 1000) | $ 1,201.4 | $ 964.5 | $ 1,207.3 | $ 1,205.5 | $ 1,306.9 | $ 1,347.4 | $ 1,468.2 | $ 2,234.9 | $ 2,572.1 | $ 2,091.6 | $ 1,910.1 | $ 1,426.4 | $ 18,936.4 |
| 36 | Raft River Geothermal Expense ($ x 1000) | $ 312.2 | $ 250.1 | $ 350.8 | $ 456.8 | $ 416.1 | $ 393.8 | $ 419.2 | $ 544.3 | $ 573.0 | $ 479.9 | $ 424.8 | $ 330.4 | $ 4,951.3 |
| 37 | Total Expense Excl. PURPA ( $ x 1000) | $ 2,730.6 | $ 2,386.0 | $ 3,591.9 | $ 4,418.9 | $ 4,898.3 | $ 4,735.4 | $ 3,741.5 | $ 7,190.4 | $ 8,130.5 | $ 7,560.8 | $ 4,687.5 | $ 3,115.8 | $ 57,187.5 |
| | Surplus Sales | | | | | | | | | | | | | |
| 38 | Energy (MWh) | 528,417.6 | 346,027.9 | 36,116.0 | 20,772.2 | 23,609.4 | 7,905.2 | 36,754.1 | 5,585.2 | 11,963.9 | 10,740.5 | 71,786.3 | 181,549.8 | 1,281,228.0 |
| 39 | Revenue Including Transmission Expenses ($ x 1000) | $ 7,195.6 | $ 3,082.5 | $ 369.1 | $ 425.7 | $ 749.1 | $ 197.4 | $ 767.7 | $ 104.7 | $ 320.7 | $ 262.5 | $ 1,562.0 | $ 3,186.3 | $ 18,223.3 |
| 40 | Transmission Expenses ($ x 1000) | $ 528.4 | $ 346.0 | $ 36.1 | $ 20.8 | $ 23.6 | $ 7.9 | $ 36.8 | $ 5.6 | $ 12.0 | $ 10.7 | $ 71.8 | $ 181.5 | $ 1,281.2 |
| 41 | Revenue Excluding Transmission Expenses ($ x 1000) | $ 6,667.2 | $ 2,736.5 | $ 332.9 | $ 404.9 | $ 725.5 | $ 189.5 | $ 730.9 | $ 99.1 | $ 308.7 | $ 251.8 | $ 1,490.2 | $ 3,004.7 | $ 16,942.0 |
| | Net Hedges | | | | | | | | | | | | | |
| 42 | Energy (MWh) | - | - | - | 21,104.0 | 12,960.0 | - | - | - | - | - | - | - | 34,064.0 |
| 43 | Cost($ X 1000) | $ - | $ - | $ - | $ 432.9 | $ 372.6 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 805.5 |
| 44 | Net Power Supply Expenses ($ x 1000) | $ 12.9 | $ 3,876.9 | $ 9,201.6 | $ 24,510.9 | $ 26,854.3 | $ 21,425.2 | $ 13,953.0 | $ 20,423.7 | $ 22,177.1 | $ 18,094.7 | $ 10,907.6 | $ 5,305.1 | $ 176,694.5 |
| 45 | PURPA ($ x 1000) | $ 24,315.9 | $ 22,421.0 | $ 18,164.8 | $ 16,550.5 | $ 16,195.2 | $ 15,245.1 | $ 12,558.6 | $ 13,866.6 | $ 13,102.3 | $ 17,356.0 | $ 19,579.1 | $ 21,842.0 | $ 211,197.2 |
| 46 | Total Net Power Supply Expenses ($ x 1000) | $ 24,328.8 | $ 26,297.9 | $ 27,366.5 | $ 41,061.5 | $ 43,049.4 | $ 36,670.2 | $ 26,511.6 | $ 34,290.3 | $ 35,279.4 | $ 35,450.6 | $ 30,486.7 | $ 27,147.1 | $ 387,891.6 |
| 47 | Sales at Customer Level (In 000s MWH) | 1,046.856 | 1,088.531 | 1,253.529 | 1,518.425 | 1,587.884 | 1,443.479 | 1,134.623 | 1,056.620 | 1,182.173 | 1,295.156 | 1,231.836 | 1,123.754 | 14,962.866 |
| 48 | Hours in Month | 720 | 744 | 720 | 744 | 744 | 720 | 744 | 720 | 744 | 744 | 672 | 744 | 8760 |
| 49 | Unit Cost / MWH (for PCAM) | $23.24 | $24.16 | $21.83 | $27.04 | $27.11 | $25.40 | $23.37 | $32.45 | $29.84 | $27.37 | $24.75 | $24.16 | $25.92 |
| | **Prices Used in Purchased Power & Surplus Sales Above:** | | | | | | | | | | | | | |
| | **Heavy Load** | | | | | | | | | | | | | |
| 50 | Portion of Purchased Power considered HL Purchases | 0.00% | 0.00% | 42.70% | 48.20% | 20.50% | 51.59% | 53.98% | 55.27% | 44.15% | 37.27% | 19.64% | 3.04% | |
| 51 | Purchased Power HL Price | 16.62 | 12.94 | 14.29 | 28.05 | 35.33 | 29.35 | 24.57 | 22.70 | 30.23 | 28.47 | 24.36 | 19.74 | |
| 52 | Portion of Surplus Sales considered HL Surplus Sales | 64.27% | 62.78% | 70.56% | 56.79% | 90.93% | 66.20% | 50.20% | 34.90% | 77.88% | 67.44% | 77.89% | 77.91% | |
| 53 | Surplus Sales HL Price | 15.42 | 12.00 | 13.26 | 26.03 | 32.78 | 27.23 | 22.80 | 21.06 | 28.05 | 26.41 | 22.61 | 18.32 | |
| | **Light Load** | | | | | | | | | | | | | |
| 54 | Portion of Purchased Power considered LL Purchases | 0.00% | 0.00% | 57.30% | 51.80% | 79.50% | 48.41% | 46.02% | 44.73% | 55.85% | 62.73% | 80.36% | 96.96% | |
| 55 | Purchased Power LL Price | 11.89 | 4.23 | 3.37 | 15.15 | 24.37 | 23.56 | 21.74 | 20.08 | 25.70 | 23.35 | 21.53 | 17.03 | |
| 56 | Portion of Surplus Sales considered LL Surplus Sales | 35.73% | 37.22% | 29.44% | 43.21% | 9.07% | 33.80% | 49.80% | 65.10% | 22.12% | 32.56% | 22.11% | 22.09% | |
| 57 | Surplus Sales LL Price | 10.37 | 3.69 | 2.94 | 13.22 | 21.25 | 20.55 | 18.96 | 17.51 | 22.42 | 20.36 | 18.77 | 14.85 | |

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 333
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

October Update and March Forecast
Combined Rate Calculation for April 2018 – March 2019

March 23, 2018

**APCU Combined Rate Calculation**
**April 2018 - March 2019**

| Line | | |
|---|---|---|
| | **OCTOBER APCU** | |
| 1 | Forecast of Normalized Sales (MWh) | 14,962,866 |
| 2 | Total Net Power Supply Expense | $397,181,877 |
| 3 | October APCU Unit Cost ($/MWh) | $26.54 |
| | **MARCH FORECAST** | |
| 4 | Forecast of Normalized Sales (MWh) | 14,962,866 |
| 5 | Total Net Power Supply Expense | $387,891,639 |
| 6 | March Forecast Unit Cost ($/MWh) | $25.92 |
| 7 | Sales Adjusted Forecast Power Cost Change | -$9,276,977 |
| 8 | Portion of Change Allowed | 95% |
| 9 | Forecast Change Allowed | ($8,813,128) |
| 10 | **March Forecast Rate ($/MWh)** | ($0.59) |
| 11 | **Combined Rate ($/MWh)** | $25.95 |

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 333
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

Year-Over-Year March Forecast Comparison

March 23, 2018

**COMPARISON OF AURORA DEVELOPED RESULTS VERSUS REPRICED METHODOLOGY**

| | AURORA DEVELOPED RESULTS | | | REPRICED USING FORWARD MARKET PRICES | | | | | DIFFERENCES | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | GENERATION | | | GENERATION | | | | | GENERATION | | | |
| | | A | B | | C | D | E | F | G | H | I | J |
| Line No. | Resource Type | 2017 March | 2018 March | Resource Type | 2017 March | | 2018 March | | (B-A) | (E-C) | (C-A) | (E-B) |
| 1 | Hydro (MWh) | 8,720,826 | 8,511,525 | Hydro (MWh) | 8,720,826 | 55% | 8,511,525 | 52% | (209,301) | (209,301) | - | - |
| 2 | Coal (MWh) | 1,930,551 | 1,571,360 | Coal (MWh) | 1,930,551 | 12% | 1,571,360 | 10% | (359,191) | (359,191) | - | - |
| 3 | Natural Gas (MWh) | 2,594,637 | 3,347,016 | Natural Gas (MWh) | 2,594,637 | 16% | 3,347,016 | 21% | 752,379 | 752,379 | - | - |
| 4 | Purchased Power & Purchased Power Agreements (MWh) | 1,487,442 | 1,189,608 | Purchased Power & Purchased Power Agreements (MWh) | 1,487,442 | 9% | 1,189,608 | 7% | (297,834) | (297,834) | - | - |
| 5 | PURPA (MWh) | 2,927,543 | 2,902,735 | PURPA (MWh) | 2,927,543 | 18% | 2,902,735 | 18% | (24,808) | (24,808) | - | - |
| 6 | Surplus Sales (MWh) | 1,742,877 | 1,281,228 | Surplus Sales (MWh) | 1,742,877 | 11% | 1,281,228 | 8% | (461,649) | (461,649) | - | - |
| 7 | System Load (MWh) | 15,918,123 | 16,241,016 | System Load (MWh) | 15,918,123 | 100% | 16,241,016 | 100% | 322,894 | 322,894 | - | - |
| 8 | System Load (aMW) | 1,817 | 1,854 | System Load (aMW) | 1,817 | | 1,854 | | 37 | 37 | - | - |

| | NET POWER SUPPLY EXPENSES | | | NET POWER SUPPLY EXPENSES | | | | | NET POWER SUPPLY EXPENSES | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | A | B | | C | D | E | F | G | H | I | J |
| | Resource Type | 2017 March | 2018 March | Resource Type | 2017 March | | 2018 March | | (B-A) | (E-C) | (C-A) | (D-B) |
| 9 | Hydro ($ x 1000) | $ - | $ - | Hydro ($ x 1000) | $ - | | $ - | | $ - | $ - | $ - | $ - |
| 10 | Coal ($ x 1000) | $ 68,096.5 | $ 58,772.1 | Coal ($ x 1000) | $ 68,096.5 | 18% | $ 58,772.1 | 15% | $ (9,324.3) | $ (9,324.3) | $ - | $ - |
| 11 | Natural Gas ($ x 1000) | $ 64,461.4 | $ 76,871.4 | Natural Gas ($ x 1000) | $ 64,461.4 | 17% | $ 76,871.4 | 20% | $ 12,410.0 | $ 12,410.0 | $ - | $ - |
| 12 | Purchased Power & Purchased Power Agreements ($ x 1000) | $ 69,334.8 | $ 63,215.2 | Purchased Power & Purchased Power Agreements ($ x 1000) | $ 64,941.9 | 17% | $ 57,993.0 | 15% | $ (6,119.6) | $ (6,948.9) | $ (4,392.9) | $ (5,222.2) |
| 13 | PURPA ($ x 1000) | $ 208,805.5 | $ 211,197.2 | PURPA ($ x 1000) | $ 208,805.5 | 54% | $ 211,197.2 | 54% | $ 2,391.6 | $ 2,391.6 | $ - | $ - |
| 14 | Surplus Sales ($ x 1000) | $ (39,478.3) | $ (25,824.4) | Surplus Sales ($ x 1000) | $ (20,535.6) | -5% | $ (16,942.0) | -4% | $ 13,653.9 | $ 3,593.6 | $ 18,942.7 | $ 8,882.4 |
| | | | | | | 0% | | | | | | |
| 15 | Total System ($ x 1000) | $ 371,219.9 | $ 384,231.4 | Total System ($ x 1000) | $ 385,769.6 | 100% | $ 387,891.6 | 100% | $ 13,011.6 | $ 2,122.0 | $ 14,549.8 | $ 3,660.2 |

Idaho Power/405
Witness: Nicole A. Blackwell

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 333
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

EIM Costs and Benefits

March 23, 2018

# Idaho Power Company
# 2018 APCU
# EIM Costs & Benefits

## 2018 Calendar Year Revenue Requirement

| | |
|---|---|
| Capital Investment | $244,492 |
| ADIT | ($12,246) |
| Accumulated Depreciation | ($1,071) |
| Amortization of Other Plant | ($12,321) |
| Net Rate Base | $218,854 |
| | |
| **Return on Rate Base** | **$16,976** |
| | |
| O&M (On-going) | $59,425 |
| Depreciation | $35,552 |
| Taxes | ($27,841) |
| **Total Operating Expenses** | **$67,136** |
| | |
| Net-to-Gross Tax Multiplier | 1.347 |
| | |
| **Total Revenue Requirement** | **$113,268** |

## EIM Benefits

| | |
|---|---|
| **Oregon Allocated EIM Benefits** | **($113,268)** |

| | |
|---|---|
| **Impact to NPSE** | **$0** |

Idaho Power/406
Witness: Nicole A. Blackwell

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 333
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

Revenue Spread for October Update and March Forecast

March 23, 2018

**Idaho Power Company**
**Revenue Spread Exhibit for 2018 APCU October Update**
**Stipulated Revenue Spread (UE 314)**

| Line No. | | |
|---|---|---|
| 1 | 2018 October Update Oregon Jurisdictional Share of Base NPSE = $26.54/MWh x 694,276.451 MWhs = | $18,426,097 |
| 2 | Base NPSE Recovered under Current APCU Rates | $18,068,893 |
| 3 | 2018 October Update Incremental Base NPSE | $357,204 |
| 4 | Oregon Allocated EIM Costs | $113,268 |
| 5 | Oregon Allocated EIM Benefits | ($113,268) |
| 6 | **Proposed October Update APCU Revenue Requirement** | **$357,204** |

| Line No. | | TOTAL SYSTEM | RESIDENTIAL (1) | GEN SRV (7) | GEN SRV SECONDARY (9-S) | GEN SRV PRIMARY (9-P) | GEN SRV TRANS (9-T) | AREA LIGHTING (15) | LG POWER PRIMARY (19-P) | LG POWER TRANS (19-T) | IRRIGATION SECONDARY (24-S) | UNMETERED GEN SERVICE (40) | MUNICIPAL ST LIGHT (41) | TRAFFIC CONTROL (42) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | **April 2018 - March 2019 Generation Level Normalized Sales (kWh)** | **748,251,156** | 209,227,304 | 20,744,179 | 130,134,511 | 17,351,238 | 3,138,528 | 475,798 | 183,804,202 | 110,241,240 | 72,113,759 | 5,904 | 989,628 | 24,865 |
| 8 | **Class Share of April 2018 - March 2019 Generation Level Normalized Sales (kWh)** | **100%** | 27.96% | 2.77% | 17.39% | 2.32% | 0.42% | 0.06% | 24.56% | 14.73% | 9.64% | 0.00% | 0.13% | 0.00% |
| 9 | **2018 October Update Class Allocated Base NPSE** | $ 357,204 | $ 99,882 | $ 9,903 | $ 62,124 | $ 8,283 | $ 1,498 | $ 227 | $ 87,746 | $ 52,628 | $ 34,426 | $ 3 | $ 472 | $ 12 |
| 10 | **June 2018 - May 2019 Loss-Adjusted Normalized Sales (kWh)** | **695,839,775** | 191,153,085 | 18,933,523 | 118,780,814 | 16,359,226 | 3,035,328 | 434,123 | 173,550,380 | 106,832,451 | 65,829,824 | 5,388 | 902,945 | 22,688 |
| 11 | **Proposed APCU Rates for 2018 October Update ($/kWh)** | **0.00051** | **0.00052** | **0.00052** | **0.00052** | **0.00051** | **0.00049** | **0.00052** | **0.00051** | **0.00049** | **0.00052** | **0.00052** | **0.00052** | **0.00052** |
| 12 | **Proposed October Update APCU Revenue Requirement** | **$357,204** | $99,882 | $9,903 | $62,124 | $8,283 | $1,498 | $227 | $87,746 | $52,628 | $34,426 | $3 | $472 | $12 |

| Line No. | | TOTAL SYSTEM | RESIDENTIAL (1) | GEN SRV (7) | GEN SRV SECONDARY (9-S) | GEN SRV PRIMARY (9-P) | GEN SRV TRANS (9-T) | AREA LIGHTING (15) | LG POWER PRIMARY (19-P) | LG POWER TRANS (19-T) | IRRIGATION SECONDARY (24-S) | UNMETERED GEN SERVICE (40) | MUNICIPAL ST LIGHT (41) | TRAFFIC CONTROL (42) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13 | **APCU Rates for 2017 October Update - Order No. 17-165** | **25.979** | 31.101 | 25.408 | 25.878 | 23.452 | 26.369 | 22.645 | 24.906 | 19.884 | 24.793 | 60.766 | 17.563 | 18.916 |
| 14 | **June 2018 - May 2019 Loss-Adjusted Normalized Sales (kWh)** | **695,839,775** | 191,153,085 | 18,933,523 | 118,780,814 | 16,359,226 | 3,035,328 | 434,123 | 173,550,380 | 106,832,451 | 65,829,824 | 5,388 | 902,945 | 22,688 |
| 15 | **Base NPSE Recovered under Current APCU Rates** | **$18,068,893** | $5,944,979 | $481,057 | $3,073,866 | $383,657 | $80,040 | $9,831 | $4,322,474 | $2,124,262 | $1,632,112 | $327 | $15,859 | $429 |

**Idaho Power Company**
**Revenue Spread Exhibit for 2018 APCU March Forecast**
**Stipulated Revenue Spread (UE 314)**

| Line No. | | |
|---|---|---|
| 1 | 2018 March Forecast NPSE = ($0.59)/MWh x 694,276.451 MWhs = | ($409,623) |

| Line No. | | TOTAL SYSTEM | RESIDENTIAL (1) | GEN SRV (7) | GEN SRV SECONDARY (9-S) | GEN SRV PRIMARY (9-P) | GEN SRV TRANS (9-T) | AREA LIGHTING (15) | LG POWER PRIMARY (19-P) | LG POWER TRANS (19-T) | IRRIGATION SECONDARY (24-S) | UNMETERED GEN SERVICE (40) | MUNICIPAL ST LIGHT (41) | TRAFFIC CONTROL (42) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | April 2018 - March 2019 Generation Level Normalized Sales (kWh) | 748,251,156 | 209,227,304 | 20,744,179 | 130,134,511 | 17,351,238 | 3,138,528 | 475,798 | 183,804,202 | 110,241,240 | 72,113,759 | 5,904 | 989,628 | 24,865 |
| 3 | Class Share of April 2018 - March 2019 Generation Level Normalized Sales (kWh) | 100% | 27.96% | 2.77% | 17.39% | 2.32% | 0.42% | 0.06% | 24.56% | 14.73% | 9.64% | 0.00% | 0.13% | 0.00% |
| 4 | 2018 March Forecast Class Allocated NPSE | $ (409,623) | $ (114,540) | $ (11,356) | $ (71,241) | $ (9,499) | $ (1,718) | $ (260) | $ (100,622) | $ (60,351) | $ (39,478) | $ (3) | $ (542) | $ (14) |
| 5 | June 2018 - May 2019 Loss-Adjusted Normalized Sales (kWh) | 695,839,775 | 191,153,085 | 18,933,523 | 118,780,814 | 16,359,226 | 3,035,328 | 434,123 | 173,550,380 | 106,832,451 | 65,829,824 | 5,388 | 902,945 | 22,688 |
| 6 | Proposed APCU Rates for 2018 March Forecast ($/kWh) | (0.00059) | (0.00060) | (0.00060) | (0.00060) | (0.00058) | (0.00057) | (0.00060) | (0.00058) | (0.00056) | (0.00060) | (0.00060) | (0.00060) | (0.00060) |
| 7 | Proposed March Forecast Revenue Requirement | ($409,623) | ($114,540) | ($11,356) | ($71,241) | ($9,499) | ($1,718) | ($260) | ($100,622) | ($60,351) | ($39,478) | ($3) | ($542) | ($14) |

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 333
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

Summary of Revenue Impact

March 23, 2018

**Idaho Power Company**
**Calculation of Revenue Impact**
**State of Oregon**
**APCU October Update/March Forecast Filing**
**Effective June 1, 2018**

**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 | 13,720 | 191,153,085 | $19,284,767 | 100.89 | ($69,408) | $19,215,359 | 100.52 | (0.36)% |
| 2 | Small General Service | 7 | 2,540 | 18,933,523 | $1,997,227 | 105.49 | ($5,884) | $1,991,344 | 105.18 | (0.29)% |
| 3 | Large General Service | 9 | 950 | 138,175,368 | $10,701,516 | 77.45 | ($43,131) | $10,658,385 | 77.14 | (0.40)% |
| 4 | Dusk to Dawn Lighting | 15 | 0 | 434,123 | $108,496 | 249.92 | ($124) | $108,372 | 249.63 | (0.11)% |
| 5 | Large Power Service | 19 | 7 | 280,382,831 | $16,974,819 | 60.54 | ($79,971) | $16,894,848 | 60.26 | (0.47)% |
| 6 | Agricultural Irrigation Service | 24 | 1,988 | 65,829,824 | $6,452,273 | 98.01 | ($20,083) | $6,432,190 | 97.71 | (0.31)% |
| 7 | Unmetered General Service | 40 | 2 | 5,388 | $548 | 101.70 | ($3) | $545 | 101.06 | (0.63)% |
| 8 | Street Lighting | 41 | 10 | 902,945 | $142,913 | 158.27 | ($215) | $142,698 | 158.04 | (0.15)% |
| 9 | Traffic Control Lighting | 42 | 8 | 22,688 | $2,139 | 94.28 | ($6) | $2,133 | 94.03 | (0.27)% |
| 10 | Total Uniform Tariffs | | 19,225 | 695,839,775 | $55,664,699 | 80.00 | ($218,824) | $55,445,874 | 79.68 | (0.39)% |
| 11 | Total Oregon Retail Sales | | 19,225 | 695,839,775 | $55,664,699 | 80.00 | ($218,824) | $55,445,874 | 79.68 | (0.39)% |

(1) Updated June 2018-May 2019 Test Year