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March 25, 2019

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Filing Center
P.O. Box 1088
201 High Street SE, Suite 100
Salem, Oregon 97301

Re: Docket No. UE 350 – In the Matter of Idaho Power Company's 2019 Annual Power Cost Update

Attention Filing Center:

Attached for filing in the above-captioned docket is Idaho Power Company's 2019 March Forecast.

Please contact this office with any questions.

Sincerely,

Alisha Till

Alisha Till
Paralegal

Attachments

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 350

IN THE MATTER OF IDAHO POWER COMPANY'S 2019 ANNUAL POWER COST UPDATE	)
	)
MARCH FORECAST	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

NICOLE A. BLACKWELL

March 25, 2019

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

A. Yes. I previously submitted direct testimony in this proceeding regarding the October Update for the 2019 Annual Power Cost Update ("APCU"). The 2019 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 2019 through March 2020.

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

A. The Company filed the 2019 October Update on October 31, 2018, and the Public Utility Commission of Oregon ("Commission") Staff ("Staff") and the Oregon Citizens' Utility Board ("CUB") reviewed the filing. Three rounds of discovery requests have been served on the Company since the initial filing. The parties held an initial workshop on January 22, 2019, to discuss the 2019 October Update filing.

On February 4, 2019, Staff filed opening testimony and CUB indicated that it would not be filing opening testimony. On March 4, 2019, the Company, Staff, and CUB filed waivers of cross-answering and reply 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, 2018. The initial October Update filing proposed a revenue decrease of approximately $9,979, or 0.02 percent. If the March Forecast and October Update are approved as filed, the 2019 composite APCU (both the October Update and March

[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).

Forecast components) will result in a revenue increase of $1.07 million or a 1.94 percent increase, to become effective June 1, 2019.

Q. What are the main factors driving the revenue change requested in this case?

A. The revenue increase requested in this case results from an increase in expected net power supply expense ("NPSE") for the March Forecast, which is partially offset by a decrease in normalized NPSE for the October Update, which has been updated since the initial October Update filing.

The requested revenue requirement for the 2019 March Forecast is approximately $0.80 million, which is a $1.22 million increase compared to the current 2018 March Forecast revenue requirement included in Oregon customer rates of negative $0.42 million. As discussed later in my testimony, the increase in NPSE for the 2019 March Forecast as compared to last year is largely attributable to higher natural gas prices and electric market prices due to the sustained effects of a major natural gas pipeline explosion that occurred in October 2018. Additionally, increased Public Utility Regulatory Policies Act of 1978 ("PURPA") generation, a must-take resource, is also causing an increase in NPSE for the 2019 March Forecast.

For the October Update, the requested revenue requirement decrease is approximately $0.15 million as compared to the revenue requirement decrease of $9,979 included in the initial October Update filing. The decrease in the October Update revenue requirement is due to an update to the Company's forecast of Energy Imbalance Market ("EIM") benefits for the April 2019 through March 2020 test period, which will be discussed later in my testimony.

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 NPSE for the 2019 March Forecast and how it compares to last year's 2018 March Forecast. My testimony concludes with the quantification of the projected revenue requirement increase and the proposed rate implementation to allocate the revenue increase to customers.

Q. Have you prepared exhibits for this proceeding?

A. Yes, I am sponsoring the following exhibits:

1. Exhibit 201, forward price curves used for re-pricing purchased power and surplus sales.
2. Exhibit 202, determination of expected NPSE for the 2019 March Forecast.
3. Exhibit 203, determination of normalized NPSE for the 2019 October Update.
4. Exhibit 204, year-over-year differences in modeled NPSE.
5. Exhibit 205, EIM costs.
6. Exhibit 206, October Update and March Forecast combined rate calculation.
7. Exhibit 207, revenue spread.
8. Exhibit 208, calculation of revenue impact.

I. 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 90 water year conditions in the AURORA model and then averaging the results of all 90 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.

II. 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. 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 2019 March Forecast and those used to develop the 2019 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 2019 through March 2020 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.

A. Fuel Expense.

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 2018 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 2019 March Forecast is $89.3 million, compared to $65.2 million in the 2019 October Update, an increase of 37 percent. Coal-fired generation increased as compared to the October Update, from 1.8 million megawatt-hours ("MWh") to 2.5 million MWh, or approximately 39 percent.

Q. How do the increases 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 $35.67 per MWh, compared to $36.74 per MWh for the October Update. At the plant level, the per-unit cost of production decreased at the Jim Bridger plant ("Bridger") from $37.92 per MWh to $35.03 per MWh, decreased at the Boardman plant ("Boardman") from $27.39 per MWh to $26.57 per MWh, and increased at the North Valmy ("Valmy") plant from $39.53 per MWh to $58.47 per MWh.

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 costs of production at Bridger and Boardman decreased between the October Update and the March Forecast primarily due to lower coal costs, on a dollar per MMBtu basis. Coal costs at these plants decreased due to an increase in expected generation and associated coal volumes, resulting in a lower cost per MMBtu. Coal costs for Bridger decreased approximately 4 percent since the October Update. Similarly, 2019 coal costs for Boardman, on a dollar per MMBtu basis, decreased approximately 4 percent between the October Update and the March Forecast. The decline in costs results in an increase in the AURORA-modeled dispatch. As a result of the decrease in costs and increase in production volumes, the per-unit costs of production at Bridger and Boardman decreased.

The per-unit cost of production at Valmy increased between the October Update and the March Forecast due to an 18 percent increase in coal costs, on a dollar per MMBtu basis. The increase in coal costs at Valmy is related to the Enbridge natural gas pipeline explosion that occurred in October 2018, which is discussed in further detail later in testimony. Due to the pipeline explosion and the resulting impact on natural gas prices and market prices, actual generation at Valmy for October 2018 through February 2019 was 134 percent higher than forecast. As a result of the increase in actual generation, the plant consumed all existing coal inventory, resulting in the need to purchase additional, higher cost coal to meet fueling needs for 2018 as well as expected generation for 2019-2020. Consequently, the coal forecast prepared for the March Forecast reflects the higher-priced coal at Valmy.

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 2019 March Forecast, Idaho Power updated the OHAG forecast using the 2016-2018 historical average of actual OHAG costs, with a growth rate equal to the 2014-2018 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 202, respectively.

Q. Does Idaho Power's 2019 March Forecast account for revenues received from or expenses paid to NV Energy (its ownership partner in the Valmy plant) for use of the Company's unused capacity or the Company's use of NV Energy's unused capacity?

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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).

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 2019 March Forecast, the 2016-2018 historical average net revenue paid to Idaho Power is $67,378 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 202, this amount has been reflected as an offset to NPSE for Valmy for the 2019 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 $3.13 per MMBtu, while the gas price forecast used for the March Forecast for Henry Hub was $2.98 per MMBtu, a decrease of $0.15 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 $2.98 per MMBtu applied to a Sumas basis of $0.13 per MMBtu equals a Sumas gas price of $3.11 per MMBtu ($2.98 + $0.13 = $3.11). The Company develops a separate gas price for its natural gas units also based upon the Henry Hub gas price forecast, referred to as the Idaho Citygate price.

Q. Please explain the Idaho Citygate price.

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[4] *Id.* at 3.

A. The Idaho Citygate price is representative of the gas price delivered to Idaho Power's natural gas units. The Idaho Citygate price is based on the Henry Hub price and applies adjustments for Sumas basis and transport costs.

Q. How does the Idaho Citygate price for the 2019 March Forecast compare to last year?

A. The average Idaho Citygate price for the 2019 March Forecast is $3.17 per MMBtu compared to $2.41 per MMBtu for the 2018 March Forecast.

Q. If the Henry Hub gas price is decreasing, why did the Idaho Citygate price increase?

A. The increase in the Idaho Citygate price for the 2019 March Forecast is attributable to a 118 percent increase in the Sumas basis. Sumas, located in Washington on the border with Canada, forms the primary natural gas trading hub for consumers in the Pacific Northwest. The increase in the Sumas basis adjustment is due to the Enbridge natural gas pipeline explosion that occurred in October 2018. The Enbridge pipeline runs from British Columbia and connects to the Northwest Pipeline system, which feeds the Pacific Northwest with natural gas. Due to the October 2018 explosion, natural gas storage in the Pacific Northwest is down 40 percent from last year. Additionally, the pipeline is expected to have several planned outages during 2019 in order to restore the pipeline to 100 percent deliverability. The Enbridge pipeline is expected to be fully restored and returned to 100 percent deliverability by October 2019.

B. <u>PURPA Expense</u>.

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

A. The October Update included 343 average megawatts ("aMW") of available PURPA generation, whereas the PURPA generation included in the March Forecast is 338 aMW, a decrease of 5 aMW, or 1.5 percent, 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 $220.4 million compared to $221.1 million included in the October Update, a decrease of $0.7 million, or 0.3 percent. As discussed later in testimony, PURPA expense included in the 2019 March Forecast is $9.8 million more than PURPA expense included in the 2018 March Forecast. This is primarily due to the addition of six new PURPA projects which account for an increase in expected generation of 8 aMW since last year's March Forecast.

Q. Does the PURPA forecast included in the 2019 March Forecast include a Contract Delay Rate ("CDR") adjustment per the terms of the 2018 APCU settlement stipulation?

A. Yes. Per the terms of the settlement stipulation approved by Order No. 18-170 in the Company's 2018 APCU, Docket No. UE 333 ("2018 Stipulation"),[5] Idaho Power applied a CDR adjustment to the PURPA forecast included in the March Forecast of the APCU. The CDR was calculated based on a three-year average of differences in scheduled operation date and actual operation date for historical PURPA projects. The CDR was then applied to the expected on-line date for all new PURPA projects included in the PURPA forecast for the 2019 March Forecast.

The 2019 March Forecast includes six new PURPA projects, including five solar projects and one hydro project. In compliance with the 2018 Stipulation, the Company calculated a three-year average CDR of 46 days and applied this rate to the scheduled operation dates for the six new projects. As an example, Idaho Power has a contract with Baker Solar Center, a 15 megawatt PURPA solar project, that specifies

[5] *In the Matter of Idaho Power Company's 2018 Annual Power Cost Update*, Docket No. UE 333, Stipulation/8 (May 1, 2018).

a scheduled operation date of December 31, 2019. Applying the CDR of 46 days, the Company determined a CDR-adjusted operation date of February 15, 2020. Accordingly, the forecast generation and expense associated with this project are included in the PURPA forecast for the 2019 March Forecast beginning in February 2020 rather than December 2019. This process was applied to all new PURPA projects included in the 2019 March Forecast. The Company will submit a workpaper to support its CDR calculation, as well as the PURPA forecast for the 2019 March Forecast.

C. <u>Normalized Load</u>.

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

A. The forecast of system normalized load used for both the October Update and the March Forecast was 1,834 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 resulted in a slight increase in the Oregon jurisdictional share of NPSE. This will be discussed in further detail later in testimony.

D. <u>Hydro Forecast</u>.

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, 2019, forecast. The forecast has expected inflows into Brownlee Reservoir for April through July of 5.43 million acre-feet ("MAF"), or 99 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 included expected inflows into Brownlee Reservoir for April through July of 5.27 MAF compared to this year's forecast of 5.43 MAF, reflecting a 3 percent increase.

Q. How does the change 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 8.4 million MWh compared to 8.5 million MWh in last year's March Forecast, a 1 percent decrease. Although expected inflows into Brownlee Reservoir for April through July are 3 percent higher than last year, forecast generation is decreasing slightly due to the timing of the increased inflows and spill conditions. Because flow through the generators is limited by the capacity of each unit, flows in excess of this capacity is spilled past the dam and cannot be used for generation.

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 (90 water years) for the October Update was 8.55 million MWh. The hydro generation forecasted for this year's March Forecast is 8.35 million MWh, a decrease of 0.2 million MWh or 2 percent as compared to the October Update, which suggests that the expected hydro generation for the March Forecast is near normal.

E. 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 202, 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.

F. <u>Re-Pricing Based on a Forward Price Curve</u>.

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

A. Exhibit 201 shows the March 1, 2019, Mid-Columbia Heavy Load (HL) and Light Load (LL) forward price curve for the April 2019 through March 2020 test period the Company used for the March Forecast, as directed by Order No. 08-238.

G. <u>Other</u>.

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.

III. 2019 FORECAST NPSE

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

A. Yes. Exhibit 202 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 2019 through March 2020 test year.

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

A. Exhibit 202 shows the results of a single water condition for the April 2019 through March 2020 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 $189.7 million. When PURPA expenses of $220.4 million and EIM benefits of $7.8 million are included, the total NPSE for the March Forecast is $402.3 million. A discussion of EIM benefits is included later in testimony.

Q. How does the 2019 March Forecast of NPSE compare to last year's March Forecast of NPSE?

A. The 2019 March Forecast of NPSE is $402.3 million, or $20.3 million more than the 2018 March Forecast of NPSE of $382.0 million.[6]

Q. How does the modeled generation in the 2019 March Forecast compare to last year's March Forecast?

A. A high-level analysis of the results suggests that higher natural gas prices and electric market prices have resulted in increased reliance on coal-fired generation to economically serve load. Additionally, PURPA generation and generation from purchased power agreements ("PPA") have increased since last year's March Forecast. The increase in electric market prices has also resulted in an increase in the Company's expectation of economic off-system sales. Exhibit 204 compares the AURORA-developed results, the re-pricing of purchased power and surplus sales, and the differences between the 2019 March Forecast and 2018 March Forecast.

Q. What are some of the differences in resource dispatch as shown in Exhibit 204?

A. Column H of Exhibit 204 shows the following: an increase in coal fuel expense of $30.8 million associated with a 0.94 million MWh increase in generation; a decrease in natural gas expense of $12.7 million associated with a decrease of 1.03 million MWh in generation; an increase in market purchased power expenses of $11.6 million associated with an increase of 0.06 million MWh; an increase in PPA expense of $3.1 million associated with an increase of 0.02 million MWh; an increase in PURPA expenses of $9.8 million associated with an increase of 0.08 million MWh; and, finally, an increase in surplus sales revenue of $19.9 million associated with an increase of 0.04 million MWh.

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[6] Final NPSE as shown in Exhibit No. 2 of the 2018 APCU Settlement Stipulation, Docket No. UE 333 (May 1, 2018).

Q. How does expected generation change from the 2018 March Forecast to the 2019 March Forecast?

A. To illustrate the changes in generation, columns D (2018) and F (2019) of Exhibit 204 calculate the percentage of generation compared to total system load. For the 2019 March Forecast, hydro generation was unchanged at 52 percent; coal generation increased from 10 percent to 16 percent; natural gas generation decreased from 21 percent to 14 percent; market purchased power was unchanged at 4 percent; PPA generation increased from 3 percent to 4 percent; PURPA generation was unchanged at 18 percent; and, lastly, surplus sales were unchanged at 8 percent. This comparison between resource type and total system load shows that higher natural gas prices and electric market prices have caused an increase in coal-fired generation to economically serve load.

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 (2018) and F (2019) of Exhibit 204 are as follows: coal fuel expense increased from 15 percent to 22 percent of total expense; natural gas decreased from 20 percent to 16 percent; market purchased power increased from 4 percent to 7 percent; PPA expense was unchanged at 11 percent; PURPA expense was unchanged at 55 percent; and surplus sales revenue increased from negative 4 percent to negative 9 percent. Exhibit 204 demonstrates that the majority of movement in expenses is related to coal, natural gas, and market power purchases and sales.

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 for the 2019 March Forecast is $27.60 per MWh compared to last year's March Forecast average per-unit cost of $22.94 per MWh, a 20 percent increase. Due to rising natural gas prices, the Company's reliance on coal-fired generation is expected to increase, whereby the average per-unit cost varies from $26.57 per MWh to $58.47 per MWh. The increase in expected PURPA generation, primarily due to the addition of six new PURPA projects, is driving a $9.8 million increase in NPSE as compared to last year's March Forecast. PURPA is a must-take resource regardless of price, which in this case averages $74.27 per MWh. Higher market prices are also driving an increase in NPSE as compared to last year. The average AURORA-modeled market purchase price (before re-pricing) for the 2019 March Forecast is $35.18 per MWh, compared to $31.02 per MWh for last year, a 13 percent increase. At the same time, higher market prices have increased the Company's expectation of economic off-system sales, resulting in a reduction to NPSE as compared to last year. The average AURORA-modeled market sales prices (before re-pricing) for the 2019 APCU is $21.51 per MWh, as compared to $20.04 for the 2018 March Forecast.

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 204, for this year's March Forecast, re-pricing of market purchases and sales results in a net decrease in NPSE of $6.5 million. The re-pricing of purchased power increased the average market purchase price of $35.18 per MWh (as modeled in AURORA) to $37.74 per MWh, resulting in a $1.8 million increase in NPSE. The re-pricing of surplus sales increased the average market sales price of $21.51 per MWh (as modeled in AURORA) to $27.81 per MWh, resulting in an increase in surplus sales revenue of $8.3 million.

A. ***EIM Costs and Benefits.***

Q. Has the Company adjusted the NPSE amounts included in the 2019 APCU to reflect Idaho Power's participation in the Western EIM?

A. Yes. The NPSE requested for approval in the 2019 APCU includes both the incremental benefits and costs associated with Idaho Power's participation in the Western EIM. Because the cost-savings benefits associated with EIM participation will be reflected as decreased NPSE, the Company believes it is appropriate to include an estimate of both the incremental benefits and the incremental costs required for participation as part of this APCU.

Q. What level of EIM benefits is Idaho Power proposing to include in the 2019 APCU?

A. Idaho Power is proposing to include $7.79 million in system EIM benefits as an offset to NPSE in the 2019 APCU. On an Oregon allocated basis, the EIM benefits to be included in the 2019 APCU total $0.36 million.

Q. How did the Company determine the level of EIM benefits to be included in the 2019 APCU?

A. The level of EIM benefits to be included in the 2019 APCU is based on a 2016 EIM benefits study completed by Energy + Environmental Economics ("E3") with an adjustment for expected greenhouse gas ("GHG") benefits. The E3 study reported a base case scenario of $4.5 million in estimated system EIM benefits that may be achieved by Idaho Power. Additionally, Idaho Power expects GHG benefits of $3.3 million for the 2019 APCU test period, for a total EIM benefit estimate of $7.8 million.

Q. Why is Idaho Power basing expected EIM benefits on a study that was completed prior to EIM participation rather than the California Independent System Operator's ("CAISO") report of benefits?

A. As stated in the October Update testimony, Idaho Power intended to perform a detailed review of the CAISO benefit calculation because the Company believes the methodology overstates benefits, particularly around the Company's hydro units. Idaho Power has been actively working with Power Settlements[7] and CAISO to shadow and validate CAISO's benefit calculation. Additionally, the Company is continuing to develop a methodology to quantify actual benefits achieved through EIM participation, which will serve as the basis for forecasting EIM benefits. As the methodology for quantifying actual benefits is not yet finalized, the Company is relying on the E3 study to estimate EIM benefits in the interim. The Company expects the methodology for quantifying actual benefits will be finalized within the next two weeks and intends to supplement the March Forecast testimony with the results of that analysis.

Q. Please describe the intent of the shadow calculation performed by Idaho Power in conjunction with Power Settlements.

A. The intent of the shadow calculation performed by Idaho Power in conjunction with Power Settlements is to validate the accuracy of the CAISO benefit calculation as well as identify and correct any inconsistencies or data errors. Additionally, the shadow calculation allows Idaho Power to run its own EIM benefit calculations using inputs and assumptions that are specific to the Company. This process allows the Company to more accurately quantify benefits specific to Idaho Power customers due to its participation in the Western EIM.

Q. Please describe any progress the Company has made in its review of the CAISO benefit calculation.

[7] Power Settlements is a software company that specializes in providing software solutions to energy companies that participate in independent system operator and regional transmission organization physical power markets.

A. During the Company's review of the CAISO benefit calculation, Idaho Power identified an issue with CAISO's counterfactual ("CF") methodology, which has resulted in CAISO changing one of its assumptions in the benefit calculation for all participating entities.

Q. Please describe the issue identified with CAISO's CF methodology that has since been corrected for all participating entities.

A. The calculation of the CAISO EIM benefits utilizes a CF methodology in which dispatch for an EIM Balancing Authority Area ("BAA") mimics operations without importing or exporting through EIM transfers. The CF dispatch moves units inside the BAA to meet real-time imbalances based on economic merit order. CAISO's quantification of total estimated EIM benefits is the cost savings of the EIM dispatch compared to the CF without EIM dispatch. To determine CF costs, the CAISO relies upon the bid stack submitted by each EIM entity.

Upon receiving CAISO's 2018 Fourth Quarter Western EIM Benefits Report, which included an initial EIM benefit of $10.4 million for Idaho Power in this quarter, the Company evaluated the CAISO benefit calculation and determined that the CF methodology was excluding some dispatchable lower-priced resources. The reason for this was that CAISO was using the transfer price[8] as a floor. Only resources with dispatchable capacity at bids equal to or higher than the transfer price were included in the CF calculation. Any resources with dispatchable capacity at bids lower than the transfer price were excluded from the CF calculation. In other words, in the Company's view, the CF was not using the least-cost available resources and therefore was overstating CF cost savings and ultimately the EIM benefits. CAISO agreed to correct this modeling assumption for all EIM entities going forward. Additionally, CAISO

[8] The transfer price is the average price of transfers between the Company and adjacent EIM BAAs.

agreed to re-run the fourth quarter benefits calculation for Idaho Power, which resulted in a corrected benefit amount of $5.8 million, a 44 percent decrease from the initial estimate.

Q. Did CAISO re-run the prior quarterly EIM benefits reports using the corrected modeling methodology?

A. No. Because of the administrative work required, CAISO chose not to re-run or re-publish prior quarters' Western EIM Benefits Reports for Idaho Power utilizing the corrected modeling methodology. However, CAISO did agree to re-run one month from both the second and third quarters of 2018 with the corrected modeling methodology. For the second quarter of 2018, CAISO re-ran its June benefits calculation, which resulted in a reduction from the initial benefits estimate of $2.64 million to $1.90 million, a 28 percent reduction. For the third quarter of 2018, CAISO re-ran its August benefits calculation, which resulted in a reduction from the initial estimate of $6.36 million to $4.43 million, a 30 percent reduction. These revised CAISO EIM benefit amounts were not published publicly but were provided to Idaho Power for informational purposes.

Q. Does CAISO's correction to the CF modeling assumption alleviate Idaho Power's concerns with CAISO's benefit calculation?

A. No. Identification of CAISO's inaccurate CF modeling assumption validated Idaho Power's concern that CAISO's methodology overstates benefits. While the Company is satisfied with CAISO's decision to correct the CF modeling assumption related to the price floor, this was one subset of Idaho Power's concerns with CAISO's modeling assumptions. The Company continues to believe that CAISO's methodology overstates benefits as it relates to hydro units. Additionally, Idaho Power has concerns that benefits related to third-party loads in the Company's BAA are included in CAISO's benefit calculation for Idaho Power.

Q. Please explain why Idaho Power believes CAISO's modeling assumptions for hydro leads to an overstatement of benefits.

A. CAISO's CF dispatch cost is based on bid prices submitted for each participating resource, which CAISO assumes is equal to the true dispatch cost, or the economic value, of the resources. For most resource types, this assumption may be reasonable; however, this assumption is not accurate for hydro resources. Because hydro is essentially a zero-variable cost resource, Idaho Power bids hydro resources based on an operational value rather than dispatch cost. When Idaho Power operators move water into the higher tiers, which have a higher bid price, it is a response to operational needs and does not reflect market benefits. Without adjusting for these operating scenarios, CAISO's CF dispatch results in a baseline that is inaccurate for reflecting cost savings of participation in the market.

Q. Please explain in further detail how Idaho Power bids hydro resources.

A. The Company has a system of hydro "tiers," both operational and pricing, for EIM offers. Operational tiers are utilized by the Company's Load Serving Operations group ("LSO"), while the pricing components associated with each tier are established by the Company's Power Supply Merchant group ("PSM"). The LSO determines available hydro energy for various operational conditions and reservoir management requirements, which is used by operators to allocate energy among a set of tiers. Based on this operational information, the PSM develops and submits bids to the EIM market operator. In other words, the LSO communicates operational goals to the PSM and the PSM establishes pricing based on these operational goals.

The LSO determines how much water should go into each tier considering multiple system condition factors, including, but not limited to, how much the EIM has already dispatched Company resources up or down in previous hours, whether Idaho Power's system is surplus or deficit compared to what was planned on preschedule, and how much flexibility the Company has to deviate from the daily targeted flows through the Company's Hells Canyon Complex. Thus, the operational tiers reflect operational goals and the amount of water that is available for each tier. Lower tiers generally reflect a greater ability to move water and generate energy with less of an impact on future planned operations.

The PSM establishes pricing tiers with the lowest tier having lower prices and higher tiers having higher prices. (Consistent with the Federal Energy Regulatory Commission's Standards of Conduct, the operators have no visibility or influence on the establishment of price, and the PSM has no visibility or influence on the amount of water placed into each tier). The PSM establishes the prices using seasonal values that include expected future energy for dispatch based on minimum flow requirements.

To manage the varying system conditions and ensure that Idaho Power manages its water appropriately, the Company is often forced to allocate energy to higher tiers to reduce volatility and maintain hydro flows within required ranges.[9] As an example, if the EIM has already increased generation significantly in previous hours, the Company may have already increased its daily average flows by the amount permitted, resulting in the need to allocate energy to higher tiers in future hours to prevent flow of more water than allowed during a particular time frame. There are also timing restrictions that impact the allocation of hydro energy among operational tiers. For example, the Company typically plans to operate its hydro generation resources in a manner that reserves water for periods of the day when demand is at its highest. If Idaho Power allocates too much energy to a lower operational tier and the EIM dispatches this energy over several hours, then the Company may not have enough water to increase generation during a higher load period and may have to purchase energy rather than relying on its own resources to serve load.

[9] Requirements may include flood control obligations, fish flow obligations, etc.

For reasons such as these, Idaho Power operators must carefully select the operational tiers into which water is placed. When Idaho Power operators move water into the higher tiers, it is a response to operational needs, which is not captured in the CF calculation. Therefore, the resulting benefits are overstated.

Q. How does Idaho Power intend to correct the modeling of hydro resources?

A. The Company is working on an alternate hydro pricing structure to CAISO's EIM benefits calculation. Specifically, Idaho Power is working on revising the inputs to the hydro bid tier prices for the fourth quarter of 2018 in order to show a zero cost for these resources, which will then be used to recalculate the CF component of the EIM benefit calculation. The Company believes this modified approach will more appropriately reflect actual savings achieved through participation of those units in the EIM.

Q. You stated that Idaho Power has concerns that benefits related to third-party loads in the Company's BAA are included in CAISO's benefit calculation. Please explain.

A. The benefits reported by CAISO reflect a value for the entire BAA each month. The Company has third-party load in its BAA whose benefits are being included in CAISO's reported benefits for Idaho Power. To better determine the benefits attributable to Idaho Power customers, the Company is working on a method to reflect the monthly EIM BAA benefits based on a load ratio allocation between Idaho Power load and third-party customer loads in the Idaho Power BAA. The Company intends to present its method and findings associated with third-party loads, as well as the alternate hydro pricing structure within the next two weeks.

Q. Please explain the GHG benefit to be included in the 2019 APCU.

A. The forecast amount of GHG benefits included in the 2019 APCU forecast of EIM benefits is $3.3 million. Idaho Power's actual GHG benefits for the prior year [10] were approximately $4.8 million. The Company reduced the estimate of GHG revenues to be included in the 2019 APCU forecast by $1.5 million due to a November 2018 change in CAISO's procedures related to the way GHG payments are awarded. The change in CAISO's GHG payment procedures significantly reduced the amount of GHG awards paid to Idaho Power after November 2018.

In estimating GHG awards for the 2019 APCU test period, for the forecast months of November through March, the Company used prior year actual results as these months were indicative of the change in CAISO's GHG payment procedure. For the forecast months of April through June, the Company also used prior year actual results as these are hydro dominated months, in which GHG benefits are minimal due to a surplus of additional hydro resources on the system driving down market prices, and resources are expected to be similarly dispatched for the forecast test year. For the forecast months of July through October, the Company discounted prior year actuals based on observed differences in actual GHG benefits after the change in CAISO's GHG payment procedure.

Q. Please summarize the final estimate of EIM benefits to be included in the 2019 APCU.

A. In the interim, the Company is utilizing the E3 study of estimated benefits, which includes a base case scenario of $4.5 million, for inclusion in the 2019 APCU. The Company has also included $3.3 million in GHG revenues in the 2019 APCU forecast of EIM benefits, for a total estimated benefit of $7.8 million, or $0.36 million on an Oregon jurisdictional basis.

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[10] April 2018 through March 2019, where March 2019 includes 14 days of actual GHG benefits and 17 days of estimates.

The Company's estimate of EIM benefits is reflected as an offset to forecast NPSE for the March Forecast, as shown in Exhibit 202. The Company has also included the estimate of EIM benefits as an offset to forecast NPSE for the October Update, as shown in Exhibit 203. The EIM benefits estimate include in the initial October Update filing was $4.5 million and base NPSE totaled $387.5 million. With the updated EIM benefits estimate of $7.8 million, normalized NPSE included in the October Update totals $384.2 million.

Q. Did the Company update the estimated EIM costs to be included in the 2019 APCU?

A. Yes. The Company updated the annual revenue requirement associated with the EIM-related costs to be included in the 2019 APCU. The EIM-related costs included in the 2019 APCU consist of the annual return on net rate base from the capital investment required to participate in the Western EIM, depreciation expense, and ongoing incremental operations and maintenance expenses. On an Oregon-allocated basis, the revenue requirement associated with EIM costs to be included in the 2019 APCU is $111,328, as shown in Exhibit 205, which is $22,847 less than the estimate included in the October Update.

B. <u>Per-Unit Cost Calculation and Quantification of the Revenue Requirement Impact</u>.

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

A. Exhibit 202 shows the normalized annual sales at the customer level for the April 2019 through March 2020 test period of 14,836,820 MWh (line 48). Based upon test period sales, the cost per-unit for the March Forecast is $27.11 per MWh ($402.3 million / 14.837 million MWh = $27.11 per MWh) (lines 47, 48, 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 2018 March Forecast unit cost per MWh was $25.53 per MWh ($382.0 million / 14.962 million MWh = $25.53 per MWh), compared to this year's March Forecast unit cost of $27.11 per MWh.

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

A. Exhibit 206 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 $25.89 per MWh. Lines 4-6 show the calculation for the March Forecast unit cost of $27.11 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 divides line 9 by line 4 to calculate the March Forecast rate of $1.16 per MWh.

Q. How does the $1.16 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 2018 through March 2019 test period was negative $0.59 per MWh, as compared to this year's April 2019 through March 2020 test period rate of $1.16 per MWh, an increase of $1.75 per MWh.

Q. How is the revenue requirement for the March Forecast calculated using the March Forecast rate unit cost of $1.16 per MWh?

A. The revenue requirement for the March Forecast is calculated by multiplying the March Forecast rate of $1.16 per MWh by the loss-adjusted Oregon jurisdictional sales for the April 2019 through March 2020 test period of 686,328.238 MWh, resulting in a revenue requirement of approximately $0.80 million, as shown on page 2 of Exhibit 207, line 1. Under the current March Forecast rate of negative $0.59 per MWh, the revenue requirement included in Oregon customer rates is approximately negative

$0.42 million. As such, the proposed 2019 March Forecast rate of $1.16 per MWh will result in a revenue requirement increase of $1.22 million compared to what is currently being collected through Oregon customer rates.

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

A. Yes. The Company revised the revenue requirement for the October Update to align with the loss-adjusted sales that were used for the March Forecast filing and to update estimates of EIM benefits and costs.

The practice of updating the loss-adjusted sales for the October Update revenue requirement is consistent with the method applied in the last seven APCU filings in Docket Nos. UE 242, UE 257, UE 279, UE 293, UE 301, UE 314, and UE 333. The April 2019 through March 2020 loss-adjusted Oregon jurisdictional sales for the October Update were 680,879.846 MWh, whereas the loss-adjusted Oregon jurisdictional sales for the March Forecast are 686,328.238, an increase of 5,448.392 MWh. The change in the loss-adjusted sales increases the October Update revenue requirement from an initial decrease of $9,979 to $26,421, an increase of $36,400.

This increase is more than offset by the revised forecast of EIM benefits and revised EIM revenue requirement from the amounts included in the initial October Update filing. The final revenue requirement associated with the October Update is a decrease of $0.15 million, or 0.26 percent. Exhibit 207 contains the revised October Update revenue requirement.

IV. RATE IMPLEMENTATION

Q. What method of allocation are you proposing to spread the revenue requirement increase associated with the 2019 APCU to the various customer classes?

A. The Company proposes to allocate the revenue requirement associated with the 2019 APCU according to the revenue spread methodology agreed upon in the 2018 Stipulation. The 2018 Stipulation established a revenue spread methodology whereby the APCU revenue requirement is allocated to individual customer classes on the basis of normalized jurisdictional forecasted sales at the generation level for the test period. Additionally, any rate increases resulting from application of this revenue spread methodology as applied to a customer class will be capped at 3 percent above the overall average rate increase on a percentage of total revenue basis. In this case, the overall average rate change as a percentage of total revenue is an increase of 1.94 percent; therefore, any rate increases applied to individual customer classes will be capped at 4.94 percent. The proposed revenue spread resulting from the application of the stipulated methodology is shown in Exhibit 207.

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 208 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 14 of Exhibit 208, the overall revenue impact of this year's combined October Update and March Forecast is an increase of $1.07 million or 1.94 percent overall. The $1.07 million increase reflects a decrease of $0.15 million in base rate revenues associated with the October Update and a $1.22 million increase in Schedule 55 revenues associated with the March Forecast, as compared to what is currently included in Oregon customers' rates related to the 2018 APCU.

Q. Does the Company intend to provide supporting workpapers for the 2019 March Forecast to Staff and CUB?

A. Yes. Idaho Power will provide its supporting workpapers to Staff and CUB within five business days of filing the 2019 March Forecast.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 350
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

March 1, 2019, Mid-Columbia Price Curve for April 2019 – March 2020

March 25, 2019

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	**3/1/2019**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**
2	**mc HL**	37.00	22.25	31.75	60.00	73.50	43.80	30.25	31.00	41.00	42.85	35.90	29.55
3	**mc LL**	29.00	14.60	14.00	33.15	39.25	31.45	24.70	25.75	33.20	32.65	28.60	23.50
4	**Reallocated Prices**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**
5	**HL PP**												
6	103.9%	38.44	23.12	32.99	62.34	76.37	45.51	31.43	32.21	42.60	44.52	37.30	30.70
7	**LL PP**												
8	107.1%	31.06	15.64	14.99	35.50	42.04	33.68	26.45	27.58	35.56	34.97	30.63	25.17
9	**HL SS**												
10	96.4%	35.67	21.45	30.61	57.84	70.85	42.22	29.16	29.88	39.52	41.31	34.61	28.49
11	**LL SS**												
12	93.4%	27.09	13.64	13.08	30.96	36.66	29.37	23.07	24.05	31.01	30.50	26.71	21.95

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 350
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

March Forecast Expected Power Supply Costs for April 1, 2019 – March 31, 2020

March 25, 2019

IPCO POWER SUPPLY EXPENSES FOR APRIL 1, 2019 -- MARCH 31, 2020 (One Hydro Condition)
Repriced Using UE 195 Settlement Methodology - 2019 March Forecast

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	1,214,177.5	1,169,085.7	833,524.5	599,345.3	548,513.4	434,986.2	452,285.4	372,904.0	464,806.8	713,750.4	711,968.4	838,047.4	8,353,394.9
	Bridger													
2	Energy (MWh)	-	-	28,608.8	357,583.1	358,788.5	236,935.5	154,621.7	213,707.8	302,459.6	256,559.9	113,418.2	20,982.2	2,043,665.3
3	AURORA Modeled Expense ($ x 1000)	$ -	$ -	$ 1,043.7	$ 12,094.4	$ 12,107.3	$ 8,112.4	$ 5,388.9	$ 7,389.4	$ 10,302.8	$ 8,137.1	$ 3,748.5	$ 709.7	$ 69,034.2
4	AURORA Modeled Handling Expense ($ x 1000)	$ -	$ -	$ 8.0	$ 100.1	$ 100.5	$ 66.3	$ 43.3	$ 59.8	$ 84.7	$ 71.8	$ 31.8	$ 5.9	$ 572.2
5	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ -	$ -	$ 1,035.7	$ 11,994.3	$ 12,006.8	$ 8,046.1	$ 5,345.6	$ 7,329.5	$ 10,218.1	$ 8,065.2	$ 3,716.8	$ 703.8	$ 68,462.0
6	IPC Share of OHAG Expense ($ x 1000)	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 3,132.2
7	Total Expense ($ x 1000)	$ 261.0	$ 261.0	$ 1,296.7	$ 12,255.3	$ 12,267.9	$ 8,307.1	$ 5,606.6	$ 7,590.6	$ 10,479.1	$ 8,326.2	$ 3,977.8	$ 964.8	$ 71,594.2
	Boardman													
8	Energy (MWh)	2,483.2	1,610.9	20,660.9	39,706.9	39,527.6	32,402.4	27,691.5	30,616.0	39,706.9	31,292.3	15,663.4	7,874.8	289,236.7
9	AURORA Modeled Expense ($ x 1000)	$ 70.0	$ 49.8	$ 534.3	$ 1,004.4	$ 1,000.3	$ 821.9	$ 708.8	$ 777.2	$ 1,004.4	$ 905.7	$ 471.4	$ 249.4	$ 7,597.7
10	AURORA Modeled Handling Expense ($ x 1000)	$ 1.0	$ 0.7	$ 8.5	$ 16.3	$ 16.2	$ 13.3	$ 11.4	$ 12.6	$ 16.3	$ 12.8	$ 6.4	$ 3.2	$ 118.6
11	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 69.0	$ 49.2	$ 525.8	$ 988.2	$ 984.1	$ 808.6	$ 697.5	$ 764.6	$ 988.2	$ 892.8	$ 465.0	$ 246.2	$ 7,479.1
12	IPC Share of OHAG Expense ($ x 1000)	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 205.3
13	Total Expense ($ x 1000)	$ 86.1	$ 66.3	$ 542.9	$ 1,005.3	$ 1,001.3	$ 825.7	$ 714.6	$ 781.7	$ 1,005.3	$ 910.0	$ 482.1	$ 263.3	$ 7,684.5
	Valmy													
14	Energy (MWh)	-	-	-	51,020.8	55,774.6	11,055.1	-	22,696.3	31,574.0	-	-	-	172,120.8
15	AURORA Modeled Expense ($ x 1000)	$ -	$ -	$ -	$ 1,957.5	$ 2,151.2	$ 459.8	$ -	$ 950.3	$ 1,277.3	$ -	$ -	$ -	$ 6,796.1
16	AURORA Modeled Handling Expense ($ x 1000)	$ -	$ -	$ -	$ 114.8	$ 125.5	$ 24.9	$ -	$ 51.1	$ 71.0	$ -	$ -	$ -	$ 387.3
17	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ -	$ -	$ -	$ 1,842.7	$ 2,025.7	$ 434.9	$ -	$ 899.2	$ 1,206.3	$ -	$ -	$ -	$ 6,408.8
18	IPC Share of OHAG Expense ($ x 1000)	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 3,722.0
19	Usage Charges Paid to IPC ($ x 1000)	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 67.4
20	Total Expense ($ x 1000)	$ 304.5	$ 304.5	$ 304.5	$ 2,147.3	$ 2,330.2	$ 739.5	$ 304.5	$ 1,203.7	$ 1,510.8	$ 304.5	$ 304.5	$ 304.5	$ 10,063.4
	Langley Gulch													
21	Energy (MWh)	29,942.8	168,746.9	186,895.3	199,049.8	198,737.9	193,607.5	180,519.2	181,804.2	197,956.2	174,227.4	155,721.1	148,535.8	2,015,744.0
22	Expense ($ x 1000)	$ 703.4	$ 2,869.3	$ 3,248.8	$ 4,232.3	$ 4,234.7	$ 3,930.4	$ 3,489.0	$ 4,345.1	$ 5,832.7	$ 4,999.1	$ 3,956.8	$ 3,254.4	$ 45,095.9
	Danskin													
23	Energy (MWh)	-	-	28,466.8	65,591.5	60,695.6	32,818.9	19,951.0	3,294.5	1,673.8	-	24.8	97.5	212,614.6
24	Expense ($ x 1000)	$ -	$ -	$ 824.9	$ 2,323.3	$ 2,156.3	$ 1,102.2	$ 633.7	$ 127.9	$ 79.5	$ -	$ 1.0	$ 3.5	$ 7,252.2
	Bennett Mountain													
25	Energy (MWh)	-	-	10,469.1	38,473.4	35,688.5	14,589.3	6,510.2	568.2	477.2	-	-	-	106,775.8
26	Expense ($ x 1000)	$ -	$ -	$ 306.5	$ 1,363.9	$ 1,267.7	$ 493.9	$ 210.0	$ 22.4	$ 23.0	$ -	$ -	$ -	$ 3,687.3
27	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 689.9	$ 712.5	$ 689.9	$ 712.5	$ 712.5	$ 689.9	$ 712.5	$ 689.9	$ 712.5	$ 711.2	$ 666.0	$ 711.2	$ 8,410.6
	Purchased Power (Excluding PURPA)													
28	Market Energy (MWh)	-	-	78,206.6	74,254.3	62,131.0	70,723.1	36,556.2	108,414.5	101,624.4	20,486.2	2,402.0	3,952.4	558,750.8
29	Elkhorn Wind Energy (MWh)	26,404.6	26,527.2	25,227.4	25,865.4	22,886.0	21,221.6	22,494.6	31,195.2	29,677.2	24,216.8	25,076.5	27,293.8	308,086.0
30	Neal Hot Springs Energy (MWh)	15,215.9	11,429.3	11,317.3	9,167.6	9,844.5	12,018.1	16,332.7	18,385.9	20,015.0	18,557.6	17,695.7	17,587.8	177,567.7
31	Raft River Geothermal Energy (MWh)	6,974.0	4,854.7	5,861.8	6,288.1	5,741.9	6,278.0	6,505.3	6,996.5	7,608.9	7,732.9	6,927.9	6,932.1	78,702.0
32	Total Energy Excl. PURPA (MWh)	48,594.5	42,811.1	120,613.2	115,575.5	100,603.3	110,240.8	81,888.8	164,992.0	158,925.5	70,993.4	52,102.2	55,766.1	1,123,106.5
33	Market Expense ($ x 1000)	$ -	$ -	$ 1,854.1	$ 3,412.3	$ 3,002.9	$ 2,769.3	$ 1,054.8	$ 3,229.7	$ 3,882.0	$ 766.6	$ 76.4	$ 99.9	$ 20,148.0
34	Elkhorn Wind Expense ($ x 1000)	$ 1,247.9	$ 1,253.7	$ 1,622.1	$ 1,995.8	$ 1,765.9	$ 1,364.5	$ 1,446.4	$ 2,407.0	$ 2,289.9	$ 1,603.9	$ 1,660.8	$ 1,328.7	$ 19,986.5
35	Neal Hot Springs Expense ($ x 1000)	$ 1,298.8	$ 975.6	$ 1,317.9	$ 1,281.1	$ 1,375.7	$ 1,399.5	$ 1,901.9	$ 2,569.2	$ 2,796.9	$ 2,198.3	$ 2,096.2	$ 1,527.2	$ 20,738.4
36	Raft River Geothermal Expense ($ x 1000)	$ 345.4	$ 240.4	$ 395.0	$ 508.5	$ 464.3	$ 423.0	$ 438.3	$ 565.7	$ 615.3	$ 531.9	$ 476.6	$ 350.5	$ 5,354.8
37	Total Expense Excl. PURPA ($ x 1000)	$ 2,892.1	$ 2,469.7	$ 5,189.1	$ 7,197.6	$ 6,608.7	$ 5,956.3	$ 4,841.4	$ 8,771.7	$ 9,584.1	$ 5,100.7	$ 4,310.1	$ 3,306.2	$ 66,227.7
	Surplus Sales													
38	Energy (MWh)	489,417.3	403,281.0	32,273.2	17,063.9	49,186.7	11,865.1	20,375.2	5,898.8	9,032.7	20,751.6	93,057.4	166,683.0	1,318,885.8
39	Revenue Including Transmission Expenses ($ x 1000)	$ 15,909.4	$ 7,401.9	$ 804.0	$ 878.1	$ 3,188.1	$ 456.6	$ 521.5	$ 168.1	$ 334.5	$ 826.0	$ 3,022.4	$ 4,484.3	$ 37,995.0
40	Transmission Expenses ($ x 1000)	$ 489.4	$ 403.3	$ 32.3	$ 17.1	$ 49.2	$ 11.9	$ 20.4	$ 5.9	$ 9.0	$ 20.8	$ 93.1	$ 166.7	$ 1,318.9
41	Revenue Excluding Transmission Expenses ($ x 1000)	$ 15,420.0	$ 6,998.6	$ 771.7	$ 861.0	$ 3,138.9	$ 444.7	$ 501.2	$ 162.2	$ 325.5	$ 805.2	$ 2,929.4	$ 4,317.6	$ 36,676.1
	Net Hedges													
42	Energy (MWh)	-	-	22,400.0	50,400.0	70,824.0	-	-	-	-	-	-	-	143,624.0
43	Cost($ X 1000)	$ -	$ -	$ 347.2	$ 1,795.4	$ 4,214.1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,356.6
44	Net Power Supply Expenses ($ x 1000)	$ (10,483.0)	$ (315.3)	$ 11,978.9	$ 32,171.8	$ 31,654.3	$ 21,600.4	$ 16,011.2	$ 23,370.8	$ 28,901.5	$ 19,546.6	$ 10,768.9	$ 4,490.3	$ 189,696.4
45	PURPA ($ x 1000)	$ 18,142.7	$ 19,200.3	$ 23,471.5	$ 25,324.2	$ 23,342.1	$ 18,523.0	$ 16,375.6	$ 17,500.6	$ 16,357.7	$ 12,846.3	$ 15,541.2	$ 13,745.7	$ 220,371.1
46	EIM Benefits													$ 7,789.4
47	Total Net Power Supply Expenses ($ x 1000)	$ 7,659.7	$ 18,885.0	$ 35,450.4	$ 57,496.1	$ 54,996.4	$ 40,123.4	$ 32,386.8	$ 40,871.4	$ 45,259.2	$ 32,393.0	$ 26,310.1	$ 18,236.0	$ 402,278.1
48	Sales at Customer Level (In 000s MWH)	1,021.841	1,071.582	1,254.632	1,530.365	1,587.786	1,431.707	1,117.569	1,038.502	1,158.405	1,291.170	1,223.800	1,109.462	14,836.820
49	Hours in Month	720	744	720	744	744	720	744	720	744	744	696	744	8784
50	Unit Cost / MWH (for PCAM)	$7.50	$17.62	$28.26	$37.57	$34.64	$28.02	$28.98	$39.36	$39.07	$25.09	$21.50	$16.44	$27.11
	Prices Used in Purchased Power & Surplus Sales Above:													
	Heavy Load													
51	Portion of Purchased Power considered HL Purchases	0.00%	0.00%	48.42%	38.94%	18.34%	46.29%	48.22%	47.77%	37.53%	25.67%	17.78%	2.06%	
52	Purchased Power HL Price	38.44	23.12	32.99	62.34	76.37	45.51	31.43	32.21	42.60	44.52	37.30	30.70	
53	Portion of Surplus Sales considered HL Surplus Sales	63.17%	60.39%	67.51%	76.25%	82.34%	70.87%	41.49%	76.12%	70.80%	86.08%	73.04%	75.78%	
54	Surplus Sales HL Price	35.67	21.45	30.61	57.84	70.85	42.22	29.16	29.88	39.52	41.31	34.61	28.49	
	Light Load													
55	Portion of Purchased Power considered LL Purchases	0.00%	0.00%	51.58%	61.06%	81.66%	53.71%	51.78%	52.23%	62.47%	74.33%	82.22%	97.94%	
56	Purchased Power LL Price	31.06	15.64	14.99	35.50	42.04	33.68	26.45	27.58	35.56	34.97	30.63	25.17	
57	Portion of Surplus Sales considered LL Surplus Sales	36.83%	39.61%	32.49%	23.75%	17.66%	29.13%	58.51%	23.88%	29.20%	13.92%	26.96%	24.22%	
58	Surplus Sales LL Price	27.09	13.64	13.08	30.96	36.66	29.37	23.07	24.05	31.01	30.50	26.71	21.95	

Idaho Power/203
Witness: Nicole A. Blackwell

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 350
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

October Update Normalized Power Supply Costs for April 1, 2019 – March 31, 2020

March 25, 2019

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR APRIL 1, 2019 -- MARCH 31, 2020 (Multiple Gas Prices/90 Hydro Year Conditions)
Repriced Using UE 195 Settlement Methodology - 2019 October Update
AVERAGE

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	892,033.4	962,605.9	933,757.4	695,002.9	535,120.7	519,164.9	510,836.3	442,334.6	647,871.1	797,103.9	794,873.9	822,506.2	8,553,211.1
	Bridger													
2	Energy (MWh)	4,506.1	246.8	21,636.3	175,405.9	208,563.8	86,788.0	60,026.4	110,545.7	157,745.8	134,789.9	78,784.2	36,191.8	1,075,230.6
3	Expense ($ x 1000)	$ 375.7	$ 219.1	$ 987.7	$ 6,384.3	$ 7,543.7	$ 3,310.4	$ 2,397.0	$ 4,193.1	$ 5,768.0	$ 5,001.6	$ 3,054.4	$ 1,538.7	$ 40,773.8
	Boardman													
4	Energy (MWh)	7,013.3	3,951.2	10,926.9	33,299.2	37,712.5	27,206.7	22,262.4	26,374.4	31,328.6	28,045.6	20,704.9	17,005.8	265,831.5
5	Expense ($ x 1000)	$ 218.5	$ 132.8	$ 319.0	$ 910.6	$ 1,026.3	$ 749.6	$ 620.7	$ 728.0	$ 857.9	$ 724.4	$ 544.0	$ 449.8	$ 7,281.5
	Valmy													
6	Energy (MWh)	6,025.1	2,953.3	16,650.0	74,794.5	87,140.6	43,206.2	36,808.4	46,444.1	72,367.6	25,271.0	13,412.3	9,219.1	434,292.3
7	Expense ($ x 1000)	$ 525.7	$ 422.5	$ 842.0	$ 2,565.7	$ 2,924.7	$ 1,648.4	$ 1,461.2	$ 1,747.6	$ 2,499.5	$ 1,129.6	$ 766.0	$ 632.9	$ 17,165.7
	Langley Gulch													
8	Energy (MWh)	191,222.9	197,467.8	190,292.1	198,952.9	199,049.3	193,611.1	195,441.4	192,756.0	202,952.8	193,661.6	171,281.6	193,755.0	2,320,444.3
9	Expense ($ x 1000)	$ 2,611.7	$ 2,607.2	$ 2,528.4	$ 3,276.2	$ 3,249.4	$ 3,130.2	$ 3,307.6	$ 3,747.5	$ 5,006.9	$ 4,461.5	$ 3,653.6	$ 3,480.9	$ 41,061.2
	Danskin													
10	Energy (MWh)	37,565.7	41,924.0	88,012.6	123,234.4	146,973.0	99,690.6	66,039.8	29,429.4	6,766.0	4,125.8	5,810.9	14,472.3	664,044.6
11	Expense ($ x 1000)	$ 879.8	$ 948.1	$ 2,073.8	$ 3,495.5	$ 4,104.5	$ 2,725.1	$ 1,863.7	$ 889.3	$ 264.4	$ 162.5	$ 209.0	$ 444.9	$ 18,060.6
	Bennett Mountain													
12	Energy (MWh)	19,492.8	22,535.2	57,620.9	86,450.0	107,378.1	67,607.4	40,115.4	12,106.4	4,157.8	1,662.9	3,346.3	5,698.5	428,171.7
13	Expense ($ x 1000)	$ 461.8	$ 513.6	$ 1,343.9	$ 2,424.3	$ 2,956.1	$ 1,850.8	$ 1,140.6	$ 364.5	$ 161.8	$ 68.2	$ 125.1	$ 177.2	$ 11,587.9
14	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 689.9	$ 712.5	$ 689.9	$ 712.5	$ 712.5	$ 689.9	$ 712.5	$ 689.9	$ 712.5	$ 711.2	$ 666.0	$ 711.2	$ 8,410.6
	Purchased Power (Excluding CSPP)													
15	Market Energy (MWh)	1,038.5	2,569.9	44,444.9	51,202.2	48,968.7	24,463.2	13,278.2	64,417.4	57,235.6	67,162.7	15,359.0	15,294.9	405,435.2
16	Elkhorn Wind Energy (MWh)	26,404.6	26,527.2	25,227.4	25,865.4	22,886.0	21,015.4	23,409.4	30,182.4	27,577.6	24,216.8	25,076.5	27,293.8	305,682.2
17	Neal Hot Springs Energy (MWh)	15,215.9	11,429.3	11,317.3	9,167.6	9,844.5	12,018.1	16,332.7	18,385.9	20,015.0	18,557.6	17,695.7	17,587.8	177,567.7
18	Raft River Geothermal Energy (MWh)	6,974.0	4,854.7	5,861.8	6,288.1	5,741.9	6,278.0	6,505.3	6,996.5	7,608.9	7,732.9	6,927.9	6,932.1	78,702.0
19	Total Energy Excl. CSPP (MWh)	49,633.0	45,381.1	86,851.5	92,523.3	87,441.1	63,774.7	59,525.6	119,982.2	112,437.1	117,669.9	65,059.2	67,108.6	967,387.0
20	Market Expense ($ x 1000)	$ 18.5	$ 42.2	$ 712.8	$ 1,294.1	$ 1,441.5	$ 663.8	$ 312.4	$ 1,657.3	$ 1,755.8	$ 2,267.9	$ 447.2	$ 367.9	$ 10,981.5
21	Elkhorn Wind Expense ($ x 1000)	$ 1,247.9	$ 1,253.7	$ 1,622.1	$ 1,995.8	$ 1,765.9	$ 1,351.3	$ 1,505.2	$ 2,328.9	$ 2,127.9	$ 1,603.9	$ 1,660.8	$ 1,328.7	$ 19,792.0
22	Neal Hot Springs Expense ($ x 1000)	$ 1,298.8	$ 975.6	$ 1,317.9	$ 1,281.1	$ 1,375.7	$ 1,399.5	$ 1,901.9	$ 2,569.2	$ 2,796.9	$ 2,198.3	$ 2,096.2	$ 1,527.2	$ 20,738.4
23	Raft River Geothermal Expense ($ x 1000)	$ 345.4	$ 240.4	$ 395.0	$ 508.5	$ 464.3	$ 423.0	$ 438.3	$ 565.7	$ 615.3	$ 531.9	$ 476.6	$ 350.5	$ 5,354.8
24	Total Expense Excl. CSPP ($ x 1000)	$ 2,910.6	$ 2,511.9	$ 4,047.7	$ 5,079.4	$ 5,047.4	$ 3,837.6	$ 4,157.9	$ 7,121.2	$ 7,295.9	$ 6,602.1	$ 4,680.8	$ 3,574.2	$ 56,866.6
	Surplus Sales													
25	Energy (MWh)	403,826.5	308,197.9	137,043.4	28,888.5	17,184.8	58,461.5	91,758.2	14,860.0	45,275.5	65,128.3	197,116.5	256,319.6	1,624,060.6
26	Revenue Including Transmission Costs ($ x 1000)	$ 6,524.2	$ 4,591.0	$ 1,992.2	$ 661.9	$ 458.7	$ 1,438.5	$ 1,957.5	$ 346.7	$ 1,259.5	$ 1,994.4	$ 5,205.0	$ 5,591.5	$ 32,021.0
27	Transmission Costs ($ x 1000)	$ 403.8	$ 308.2	$ 137.0	$ 28.9	$ 17.2	$ 58.5	$ 91.8	$ 14.9	$ 45.3	$ 65.1	$ 197.1	$ 256.3	$ 1,624.1
28	Revenue Excluding Transmission Costs ($ x 1000)	$ 6,120.4	$ 4,282.8	$ 1,855.1	$ 633.0	$ 441.5	$ 1,380.0	$ 1,865.8	$ 331.9	$ 1,214.3	$ 1,929.2	$ 5,007.9	$ 5,335.1	$ 30,397.0
29	Net Power Supply Expenses ($ x 1000)	$ 2,553.3	$ 3,785.0	$ 10,977.4	$ 24,215.4	$ 27,123.1	$ 16,561.9	$ 13,795.4	$ 19,149.2	$ 21,352.6	$ 16,931.9	$ 8,691.1	$ 5,674.7	$ 170,810.9
30	PURPA ($ x 1000)	$ 18,289.6	$ 19,436.9	$ 23,592.1	$ 25,701.6	$ 23,739.1	$ 18,762.0	$ 17,054.0	$ 16,644.2	$ 15,666.5	$ 12,866.7	$ 15,583.0	$ 13,799.4	$ 221,135.0
31	EIM Benefits													$ 7,789.4
32	Total Net Power Supply Expenses ($ x 1000)	$ 20,842.9	$ 23,221.9	$ 34,569.4	$ 49,917.1	$ 50,862.2	$ 35,323.9	$ 30,849.4	$ 35,793.3	$ 37,019.1	$ 29,798.5	$ 24,274.1	$ 19,474.0	$ 384,156.5
33	Sales at Customer Level (In 000s MWH)	1,021.841	1,071.582	1,254.632	1,530.365	1,587.786	1,431.707	1,117.569	1,038.502	1,158.405	1,291.170	1,223.800	1,109.462	14,836.820
34	Hours in Month	720	744	720	744	744	720	744	721	744	744	696	743	8784
35	Unit Cost / MWH (for PCAM)	$20.40	$21.67	$27.55	$32.62	$32.03	$24.67	$27.60	$34.47	$31.96	$23.08	$19.84	$17.55	$25.89
	Prices Used in Purchased Power & Surplus Sales Above:													
	Heavy Load													
36	Portion of Purchased Power considered HL Purchases	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	
37	Purchased Power HL Price	$19.72	$19.07	$19.20	$29.19	$33.20	$29.55	$24.69	$26.96	$32.58	$35.95	$30.40	$25.02	
38	Portion of Surplus Sales considered HL Surplus Sales	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	
39	Surplus Sales HL Price	$18.30	$17.69	$17.82	$27.09	$30.80	$27.41	$22.91	$25.01	$30.23	$33.35	$28.21	$23.21	
	Light Load													
40	Portion of Purchased Power considered LL Purchases	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	
41	Purchased Power LL Price	$14.39	$11.69	$10.35	$18.23	$22.67	$22.80	$21.42	$23.51	$27.25	$29.85	$26.81	$22.32	
42	Portion of Surplus Sales considered LL Surplus Sales	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	
43	Surplus Sales LL Price	$12.55	$10.19	$9.02	$15.90	$19.77	$19.89	$18.68	$20.50	$23.77	$26.03	$23.38	$19.46	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 350
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

Year-Over-Year March Forecast Comparison

March 25, 2019

IDAHO POWER COMPANY
YEAR OVER YEAR DIFFERENCES IN AURORA DEVELOPED NPSE
2019 MARCH FORECAST

AURORA DEVELOPED NPSE RESULTS BEFORE MARKET ENERGY RE-PRICING

	GENERATION		
		A	B
Line No.	Resource Type	2018 March Forecast	2019 March Forecast
1	Hydro (MWh)	8,511,525	8,353,395
2	Coal (MWh)	1,565,150	2,505,023
3	Natural Gas (MWh)	3,364,548	2,335,134
4	Market Purchased Power (MWh)	645,373	702,375
5	Purchased Power Agreements (MWh)	543,697	564,356
6	PURPA (MWh)	2,889,715	2,967,158
7	Surplus Sales (MWh)	1,278,960	1,318,886
8	System Generation (MWh)	17,520,008	17,427,441
9	System Load (MWh)	16,241,049	16,108,555
10	System Load (aMW)	1,854	1,834
	NET POWER SUPPLY EXPENSES		
		A	B
	Resource Type	2018 March Forecast	2019 March Forecast
11	Hydro ($ x 1000)	$ -	$ -
12	Coal ($ x 1000)	$ 58,508.1	$ 89,342.1
13	Natural Gas ($ x 1000)	$ 77,187.9	$ 64,446.0
14	Market Purchased Power ($ x 1000)	$ 20,022.1	$ 24,710.4
15	Purchased Power Agreements ($ x 1000)	$ 43,024.4	$ 46,079.8
16	PURPA ($ x 1000)	$ 210,568.1	$ 220,371.1
17	Surplus Sales ($ x 1000)	$ (25,628.8)	$ (28,367.5)
18	EIM Benefits	$ (5,500.0)	$ (7,789.4)
19	Total System ($ x 1000)	$ 378,181.8	$ 408,792.4

REPRICED USING FORWARD MARKET PRICES

	GENERATION				
		C	D	E	F
Line No.	Resource Type	2018 March Forecast		2019 March Forecast	
1	Hydro (MWh)	8,511,525	52%	8,353,395	52%
2	Coal (MWh)	1,565,150	10%	2,505,023	16%
3	Natural Gas (MWh)	3,364,548	21%	2,335,134	14%
4	Market Purchased Power (MWh)	645,373	4%	702,375	4%
5	Purchased Power Agreements (MWh)	543,697	3%	564,356	4%
6	PURPA (MWh)	2,889,715	18%	2,967,158	18%
7	Surplus Sales (MWh)	1,278,960	-8%	1,318,886	-8%
8	System Generation (MWh)	17,520,008		17,427,441	
9	System Load (MWh)	16,241,049	100%	16,108,555	100%
10	System Load (aMW)	1,854		1,834	
	NET POWER SUPPLY EXPENSES				
		C	D	E	F
	Resource Type	2018 March Forecast		2019 March Forecast	
11	Hydro ($ x 1000)	$ -		$ -	
12	Coal ($ x 1000)	$ 58,508.1	15%	$ 89,342.1	22%
13	Natural Gas ($ x 1000)	$ 77,187.9	20%	$ 64,446.0	16%
14	Market Purchased Power ($ x 1000)	$ 14,938.0	4%	$ 26,504.6	7%
15	Purchased Power Agreements ($ x 1000)	$ 43,024.4	11%	$ 46,079.8	11%
16	PURPA ($ x 1000)	$ 210,568.1	55%	$ 220,371.1	55%
17	Surplus Sales ($ x 1000)	$ (16,771.4)	-4%	$ (36,676.1)	-9%
18	EIM Benefits	$ (5,500.0)	-1%	$ (7,789.4)	-2%
19	Total System ($ x 1000)	$ 381,955.0	100%	$ 402,278.1	100%

DIFFERENCES

	GENERATION			
	G	H	I	J
Line No.	(B-A)	(E-C)	(C-A)	(E-B)
1	(158,130)	(158,130)	-	-
2	939,873	939,873	-	-
3	(1,029,414)	(1,029,414)	-	-
4	57,002	57,002	-	-
5	20,658	20,658	-	-
6	77,443	77,443	-	-
7	39,926	39,926	-	-
8				
9	(132,494)	(132,494)	-	-
10	(20)	(20)	-	-
	NET POWER SUPPLY EXPENSES			
	G	H	I	J
	(B-A)	(E-C)	(C-A)	(E-B)
11	$ -	$ -	$ -	$ -
12	$ 30,834.0	$ 30,834.0	$ -	$ -
13	$ (12,741.9)	$ (12,741.9)	$ -	$ -
14	$ 4,688.3	$ 11,566.6	$ (5,084.1)	$ 1,794.2
15	$ 3,055.4	$ 3,055.4	$ -	$ -
16	$ 9,803.0	$ 9,803.0	$ -	$ -
17	$ (2,738.7)	$ (19,904.7)	$ 8,857.4	$ (8,308.6)
18	$ (2,289.4)	$ (2,289.4)	$ -	$ -
19	$ 30,610.7	$ 20,323.0	$ 3,773.3	$ (6,514.4)

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 350
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

Energy Imbalance Market Costs

March 25, 2019

Idaho Power Company
2019 APCU
Oregon Jurisdictional EIM Revenue Requirement

2019 Calendar Year Revenue Requirement

Capital Investment	$353,712
ADIT	($9,176)
Accumulated Depreciation	($1,468)
Amortization of Other Plant	($39,471)
Net Rate Base	$303,597
Return on Rate Base	**$23,550**
O&M (On-going)	$34,429
Depreciation	$49,385
Taxes	($24,692)
Total Operating Expenses	**$59,122**
Net-to-Gross Tax Multiplier	1.347
Total Revenue Requirement	**$111,328**

Idaho Power/206
Witness: Nicole A. Blackwell

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 350
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

October Update and March Forecast
Combined Rate Calculation for April 2019 – March 2020

March 25, 2019

APCU Combined Rate Calculation
April 2019 - March 2020

Line		
	OCTOBER APCU	
1	Forecast of Normalized Sales (MWh)	14,836,820
2	Total Net Power Supply Expense	$384,156,490
3	October APCU Unit Cost ($/MWh)	$25.89
	MARCH FORECAST	
4	Forecast of Normalized Sales (MWh)	14,836,820
5	Total Net Power Supply Expense	$402,278,053
6	March Forecast Unit Cost ($/MWh)	$27.11
7	Sales Adjusted Forecast Power Cost Change	$18,100,920
8	Portion of Change Allowed	95%
9	Forecast Change Allowed	$17,195,874
10	**March Forecast Rate ($/MWh)**	$1.16
11	**Combined Rate ($/MWh)**	$27.05

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 350
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

Revenue Spread for October Update and March Forecast

March 25, 2019

Idaho Power Company
Stipulated Revenue Spread
2019 October Update

Line No.		
1	2019 October Update Oregon Jurisdictional Share of Base NPSE = $25.89/MWh x 686,328,238 MWhs =	$ 17,769,038
2	Oregon Allocated EIM Costs	$ 111,328
3	**Proposed October Update APCU Revenue Requirement**	**$ 17,880,366**

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)
4	**April 2019 - March 2020 Generation Level Normalized Sales (kWh)**	**739,054,443**	200,415,527	20,337,588	128,830,884	16,293,835	2,945,056	474,418	178,538,874	116,192,364	74,019,084	5,904	976,356	24,553
5	**Class Share of April 2019 - March 2020 Generation Level Normalized Sales (kWh)**	**100%**	27.12%	2.75%	17.43%	2.20%	0.40%	0.06%	24.16%	15.72%	10.02%	0.00%	0.13%	0.00%
6	**2019 October Update Class Allocated Base NPSE**	$ 17,880,366	$ 4,848,767	$ 492,039	$ 3,116,879	$ 394,206	$ 71,251	$ 11,478	$ 4,319,493	$ 2,811,108	$ 1,790,786	$ 143	$ 23,622	$ 594
7	**June 2019 - May 2020 Loss-Adjusted Normalized Sales (kWh)**	**687,203,565**	182,860,882	18,577,243	117,685,671	15,372,234	2,848,217	432,863	168,443,209	112,485,084	67,579,536	5,388	890,836	22,402
8	**Proposed APCU Base Rates for 2019 October Update ($/kWh)**	**0.026019**	**0.026516**	**0.026486**	**0.026485**	**0.025644**	**0.025016**	**0.026516**	**0.025644**	**0.024991**	**0.026499**	**0.026511**	**0.026516**	**0.026517**
9	**Proposed October Update APCU Revenue Requirement**	**$ 17,880,366**	$ 4,848,767	$ 492,039	$ 3,116,879	$ 394,206	$ 71,251	$ 11,478	$ 4,319,493	$ 2,811,108	$ 1,790,786	$ 143	$ 23,622	$ 594

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)
10	**Current APCU Base Rates for 2018 October Update ($/kWh) - Order No. 18-170**	**0.026284**	0.027402	0.027429	0.027428	0.025801	0.025886	0.027439	0.026514	0.021840	0.027425	0.027433	0.022934	0.022111
11	**June 2019 - May 2020 Loss-Adjusted Normalized Sales (kWh)**	**687,203,565**	182,860,882	18,577,243	117,685,671	15,372,234	2,848,217	432,863	168,443,209	112,485,084	67,579,536	5,388	890,836	22,402
12	**Base NPSE Recovered under Current APCU Base Rates**	**$ 18,027,784**	$ 5,010,833	$ 509,563	$ 3,227,913	$ 396,620	$ 73,730	$ 11,877	$ 4,466,172	$ 2,456,630	$ 1,853,372	$ 148	$ 20,430	$ 495

Idaho Power Company
Revenue Spread Exhibit for 2019 APCU March Forecast
Stipulated Revenue Spread

Line No.			
1	Oregon Jurisdictional Share of 2019 March Forecast NPSE = $1.16/MWh x 686,328.238 MWhs =	$ 796,141	

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 2019 - March 2020 Generation Level Normalized Sales (kWh)	739,054,443	200,415,527	20,337,588	128,830,884	16,293,835	2,945,056	474,418	178,538,874	116,192,364	74,019,084	5,904	976,356	24,553
3	Class Share of April 2019 - March 2020 Generation Level Normalized Sales (kWh)	100%	27.12%	2.75%	17.43%	2.20%	0.40%	0.06%	24.16%	15.72%	10.02%	0.00%	0.13%	0.00%
4	2019 March Forecast Class Allocated NPSE	$ 796,141	$ 215,896	$ 21,909	$ 138,782	$ 17,552	$ 3,173	$ 511	$ 192,330	$ 125,167	$ 79,736	$ 6	$ 1,052	$ 26
5	June 2019 - May 2020 Loss-Adjusted Normalized Sales (kWh)	687,203,565	182,860,882	18,577,243	117,685,671	15,372,234	2,848,217	432,863	168,443,209	112,485,084	67,579,536	5,388	890,836	22,402
6	Proposed APCU Rates for 2019 March Forecast ($/kWh)	0.00116	0.00118	0.00118	0.00118	0.00114	0.00111	0.00118	0.00114	0.00111	0.00118	0.00118	0.00118	0.00118
7	Proposed March Forecast Revenue Requirement	$ 796,141	$ 215,896	$ 21,909	$ 138,782	$ 17,552	$ 3,173	$ 511	$ 192,330	$ 125,167	$ 79,736	$ 6	$ 1,052	$ 26

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)
8	APCU Rates for 2018 March Forecast - Order No. 18-170 ($/kWh)	(0.00062)	(0.00063)	(0.00063)	(0.00063)	(0.00061)	(0.00059)	(0.00063)	(0.00061)	(0.00059)	(0.00063)	(0.00063)	(0.00063)	(0.00063)
9	June 2019 - May 2020 Loss-Adjusted Normalized Sales (kWh)	687,203,565	182,860,882	18,577,243	117,685,671	15,372,234	2,848,217	432,863	168,443,209	112,485,084	67,579,536	5,388	890,836	22,402
10	NPSE Recovered under Current March Forecast Rate	$ (424,940)	$ (115,142)	$ (11,709)	$ (74,173)	$ (9,380)	$ (1,694)	$ (273)	$ (102,627)	$ (66,775)	$ (42,588)	$ (3)	$ (562)	$ (14)

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2019

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 Base Revenue w/o NPSE	Current Base NPSE Revenue	Total Current Base Revenue	Proposed Base NPSE Revenue	Total Proposed Base Revenue	Proposed Adjustments to Base Revenue	Percent Change Base to Base Revenue	Current Billed Revenue w/o March Forecast	Current Billed March Forecast Revenue	Total Current Billed Revenue	Proposed March Forecast Revenue	Proposed Adjustments to March Forecast Revenue	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Percent Change Billed to Billed Revenue	Stipulated Revenue Increase Cap (4.94%)	Revenue Requirement Shortfall
	Uniform Tariff Rates:																				
1	Residential Service	1	13,373	182,860,882	$ 12,912,980	$ 5,010,833	$ 17,923,813	$ 4,848,767	$ 17,761,747	$ (162,066)	(0.90)%	$ 17,981,868	$ (115,142)	$ 17,866,726	$ 215,896	$ 331,038	$ 168,973	$ 18,035,698	0.95%	$ 168,973	$ -
2	Small General Service	7	2,597	18,577,243	$ 1,513,267	$ 509,563	$ 2,022,830	$ 492,039	$ 2,005,306	$ (17,524)	(0.87)%	$ 2,022,821	$ (11,709)	$ 2,011,112	$ 21,909	$ 33,618	$ 16,093	$ 2,027,205	0.80%	$ 16,093	$ -
3	Large General Secondary	9S	952	117,685,671	$ 6,339,412	$ 3,227,913	$ 9,567,325	$ 3,116,879	$ 9,456,291	$ (111,034)	(1.16)%	$ 9,567,264	$ (74,173)	$ 9,493,091	$ 138,782	$ 212,955	$ 101,921	$ 9,595,012	1.07%	$ 101,921	$ -
4	Large General Primary	9P	5	15,372,234	$ 727,274	$ 396,620	$ 1,123,893	$ 394,206	$ 1,121,480	$ (2,414)	(0.21)%	$ 1,123,886	$ (9,380)	$ 1,114,506	$ 17,552	$ 26,932	$ 24,518	$ 1,139,024	2.20%	$ 24,518	$ -
5	Large General Transmission	9T	1	2,848,217	$ 118,803	$ 73,730	$ 192,533	$ 71,251	$ 190,054	$ (2,479)	(1.29)%	$ 192,531	$ (1,694)	$ 190,837	$ 3,173	$ 4,867	$ 2,388	$ 193,225	1.25%	$ 2,388	$ -
6	Dusk to Dawn Lighting	15	0	432,863	$ 96,490	$ 11,877	$ 108,367	$ 11,478	$ 107,968	$ (399)	(0.37)%	$ 108,367	$ (273)	$ 108,094	$ 511	$ 784	$ 385	$ 108,479	0.36%	$ 385	$ -
7	Large Power Primary	19P	6	168,443,209	$ 6,508,337	$ 4,466,172	$ 10,974,509	$ 4,319,493	$ 10,827,830	$ (146,679)	(1.34)%	$ 10,974,422	$ (102,627)	$ 10,871,795	$ 192,330	$ 294,956	$ 148,277	$ 11,020,072	1.36%	$ 148,277	$ -
8	Large Power Transmission	19T	1	112,485,084	$ 4,359,654	$ 2,456,630	$ 6,816,284	$ 2,811,108	$ 7,170,763	$ 354,479	5.20%	$ 6,816,226	$ (66,775)	$ 6,749,451	$ 125,167	$ 191,942	$ 546,421	$ 7,295,872	8.10%	$ 333,423	$ 212,998
9	Agricultural Irrigation Service	24	2,025	67,579,536	$ 4,986,957	$ 1,853,372	$ 6,840,329	$ 1,790,786	$ 6,777,743	$ (62,587)	(0.91)%	$ 6,840,294	$ (42,588)	$ 6,797,706	$ 79,736	$ 122,325	$ 59,738	$ 6,857,444	0.88%	$ 59,738	$ -
10	Unmetered General Service	40	2	5,388	$ 248	$ 148	$ 395	$ 143	$ 390	$ (5)	(1.26)%	$ 395	$ (3)	$ 392	$ 6	$ 10	$ 5	$ 397	1.22%	$ 5	$ -
11	Street Lighting	41	26	890,836	$ 124,551	$ 20,430	$ 144,981	$ 23,622	$ 148,172	$ 3,191	2.20%	$ 144,981	$ (562)	$ 144,419	$ 1,052	$ 1,613	$ 4,805	$ 149,224	3.33%	$ 4,805	$ -
12	Traffic Control Lighting	42	8	22,402	$ 1,680	$ 495	$ 2,175	$ 594	$ 2,274	$ 99	4.54%	$ 2,175	$ (14)	$ 2,161	$ 26	$ 41	$ 139	$ 2,301	6.44%	$ 107	$ 33
13	Total Uniform Tariffs		18,996	687,203,565	$ 37,689,651	$ 18,027,784	$ 55,717,436	$ 17,880,366	$ 55,570,017	$ (147,418)	(0.26)%	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ 1,073,662	$ 56,423,952	1.94%	$ 860,632	$ 213,030
14	Total Oregon Retail Sales		18,996	687,203,565	$ 37,689,651	$ 18,027,784	$ 55,717,436	$ 17,880,366	$ 55,570,017	$ (147,418)	(0.26)%	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ 1,073,662	$ 56,423,952	1.94%		

(1) Updated June 2019-May 2020 Test Year

Idaho Power Company
Revenue Spread Exhibit for 2019 APCU
Stipulated Revenue Spread

Line No.		
1	4.94% Increase Cap - Revenue Requirement Shortfall	$ 213,030

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 2019 - March 2020 Generation Level Normalized Sales (kWh)**	**622,837,526**	200,415,527	20,337,588	128,830,884	16,293,835	2,945,056	474,418	178,538,874		74,019,084	5,904	976,356	
3	**Class Share of April 2019 - March 2020 Generation Level Normalized Sales (kWh)**	**100%**	32.18%	3.27%	20.68%	2.62%	0.47%	0.08%	28.67%		11.88%	0.00%	0.16%	
4	**2019 APCU Class Allocated Revenue Requirement Shortfall**	**$ 213,030**	$ 68,548	$ 6,956	$ 44,064	$ 5,573	$ 1,007	$ 162	$ 61,066		$ 25,317	$ 2	$ 334	
5	**June 2019 - May 2020 Loss-Adjusted Normalized Sales (kWh)**	**574,696,079**	182,860,882	18,577,243	117,685,671	15,372,234	2,848,217	432,863	168,443,209		67,579,536	5,388	890,836	
6	**2019 APCU Revenue Requirement Shortall Rates ($/kWh)**	**0.00037**	**0.00037**	**0.00037**	**0.00037**	**0.00036**	**0.00035**	**0.00037**	**0.00036**		**0.00037**	**0.00037**	**0.00037**	

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2019

Summary of Revenue Impact
Current Base Revenue to Proposed Base Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers	Normalized Energy (kWh)	Current Base Revenue w/o NPSE	Current Base NPSE Revenue	Total Current Base Revenue	Proposed Base NPSE Revenue	Total Proposed Base Revenue	Proposed Adjustments to Base Revenue	Percent Change Base to Base Revenue	1st Pass Adjustment to Proposed Base NPSE Revenue	1st Pass Proposed Adjustments to Base Revenue	1st Pass Percent Change Base to Base Revenue	1st Pass Proposed Base NPSE Revenue	Revised APCU Rates for 2019 October Update ($/kWh)
	Uniform Tariff Rates:															
1	Residential Service	1	13,373	182,860,882	$ 12,912,980	$ 5,010,833	$ 17,923,813	$ 4,848,767	$ 17,761,747	$ (162,066)	(0.90)%	$ 68,548	$ (93,517)	(0.52)%	$ 4,917,316	0.026891
2	Small General Service	7	2,597	18,577,243	$ 1,513,267	$ 509,563	$ 2,022,830	$ 492,039	$ 2,005,306	$ (17,524)	(0.87)%	$ 6,956	$ (10,568)	(0.52)%	$ 498,995	0.026861
3	Large General Secondary	9S	952	117,685,671	$ 6,339,412	$ 3,227,913	$ 9,567,325	$ 3,116,879	$ 9,456,291	$ (111,034)	(1.16)%	$ 44,064	$ (66,970)	(0.70)%	$ 3,160,943	0.026859
4	Large General Primary	9P	5	15,372,234	$ 727,274	$ 396,620	$ 1,123,893	$ 394,206	$ 1,121,480	$ (2,414)	(0.21)%	$ 5,573	$ 3,159	0.28%	$ 399,779	0.026007
5	Large General Transmission	9T	1	2,848,217	$ 118,803	$ 73,730	$ 192,533	$ 71,251	$ 190,054	$ (2,479)	(1.29)%	$ 1,007	$ (1,471)	(0.76)%	$ 72,259	0.025370
6	Dusk to Dawn Lighting	15	0	432,863	$ 96,490	$ 11,877	$ 108,367	$ 11,478	$ 107,968	$ (399)	(0.37)%	$ 162	$ (237)	(0.22)%	$ 11,640	0.026891
7	Large Power Primary	19P	6	168,443,209	$ 6,508,337	$ 4,466,172	$ 10,974,509	$ 4,319,493	$ 10,827,830	$ (146,679)	(1.34)%	$ 61,066	$ (85,613)	(0.78)%	$ 4,380,559	0.026006
8	Large Power Transmission	19T	1	112,485,084	$ 4,359,654	$ 2,456,630	$ 6,816,284	$ 2,811,108	$ 7,170,763	$ 354,479	5.20%	$ -	$ 141,481	2.08%	$ 2,598,110	0.023097
9	Agricultural Irrigation Service	24	2,025	67,579,536	$ 4,986,957	$ 1,853,372	$ 6,840,329	$ 1,790,786	$ 6,777,743	$ (62,587)	(0.91)%	$ 25,317	$ (37,270)	(0.54)%	$ 1,816,103	0.026874
10	Unmetered General Service	40	2	5,388	$ 248	$ 148	$ 395	$ 143	$ 390	$ (5)	(1.26)%	$ 2	$ (3)	(0.75)%	$ 145	0.026885
11	Street Lighting	41	26	890,836	$ 124,551	$ 20,430	$ 144,981	$ 23,622	$ 148,172	$ 3,191	2.20%	$ 334	$ 3,525	2.43%	$ 23,955	0.026891
12	Traffic Control Lighting	42	8	22,402	$ 1,680	$ 495	$ 2,175	$ 594	$ 2,274	$ 99	4.54%	$ -	$ 66	3.04%	$ 562	0.025066
13	Total Uniform Tariffs		18,996	687,203,565	$ 37,689,651	$ 18,027,784	$ 55,717,436	$ 17,880,366	$ 55,570,017	$ (147,418)	(0.26)%	$ 213,030	$ (147,418)	(0.26)%	$ 17,880,366	
14	Total Oregon Retail Sales		18,996	687,203,565	$ 37,689,651	$ 18,027,784	$ 55,717,436	$ 17,880,366	$ 55,570,017	$ (147,418)	(0.26)%	$ 213,030	$ (147,418)	(0.26)%	$ 17,880,366	

(1) Updated June 2019-May 2020 Test Year

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2019

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 w/o March Forecast	Current Billed March Forecast Revenue	Total Current Billed Revenue	Proposed March Forecast Revenue	Proposed Adjustments to March Forecast Revenue	Proposed Adjustments to Base Revenue	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:												
1	Residential Service	1	13,373	182,860,882	$ 17,981,868	$ (115,142)	$ 17,866,726	$ 215,896	$ 331,038	$ (93,517)	$ 237,521	$ 18,104,247	1.33%
2	Small General Service	7	2,597	18,577,243	$ 2,022,821	$ (11,709)	$ 2,011,112	$ 21,909	$ 33,618	$ (10,568)	$ 23,049	$ 2,034,161	1.15%
3	Large General Secondary	9S	952	117,685,671	$ 9,567,264	$ (74,173)	$ 9,493,091	$ 138,782	$ 212,955	$ (66,970)	$ 145,985	$ 9,639,076	1.54%
4	Large General Primary	9P	5	15,372,234	$ 1,123,886	$ (9,380)	$ 1,114,506	$ 17,552	$ 26,932	$ 3,159	$ 30,091	$ 1,144,597	2.70%
5	Large General Transmission	9T	1	2,848,217	$ 192,531	$ (1,694)	$ 190,837	$ 3,173	$ 4,867	$ (1,471)	$ 3,395	$ 194,232	1.78%
6	Dusk to Dawn Lighting	15	0	432,863	$ 108,367	$ (273)	$ 108,094	$ 511	$ 784	$ (237)	$ 547	$ 108,641	0.51%
7	Large Power Primary	19P	6	168,443,209	$ 10,974,422	$ (102,627)	$ 10,871,795	$ 192,330	$ 294,956	$ (85,613)	$ 209,343	$ 11,081,138	1.93%
8	Large Power Transmission	19T	1	112,485,084	$ 6,816,226	$ (66,775)	$ 6,749,451	$ 125,167	$ 191,942	$ 141,481	$ 333,423	$ 7,082,874	4.94%
9	Agricultural Irrigation Service	24	2,025	67,579,536	$ 6,840,294	$ (42,588)	$ 6,797,706	$ 79,736	$ 122,325	$ (37,270)	$ 85,055	$ 6,882,761	1.25%
10	Unmetered General Service	40	2	5,388	$ 395	$ (3)	$ 392	$ 6	$ 10	$ (3)	$ 7	$ 399	1.74%
11	Street Lighting	41	26	890,836	$ 144,981	$ (562)	$ 144,419	$ 1,052	$ 1,613	$ 3,525	$ 5,139	$ 149,557	3.56%
12	Traffic Control Lighting	42	8	22,402	$ 2,175	$ (14)	$ 2,161	$ 26	$ 41	$ 66	$ 107	$ 2,268	4.94%
13	Total Uniform Tariffs		18,996	687,203,565	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ (147,418)	$ 1,073,662	$ 56,423,952	1.94%
14	Total Oregon Retail Sales		18,996	687,203,565	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ (147,418)	$ 1,073,662	$ 56,423,952	1.94%

(1) Updated June 2019-May 2020 Test Year

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 350
MARCH FORECAST

Exhibit Accompanying Testimony of Nicole A. Blackwell

Summary of Revenue Impact

March 25, 2019

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2019

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 w/o March Forecast	Current Billed March Forecast Revenue	Total Current Billed Revenue	Proposed March Forecast Revenue	Proposed Adjustments to March Forecast Revenue	Proposed Adjustments to Base Revenue	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:												
1	Residential Service	1	13,373	182,860,882	$ 17,981,868	$ (115,142)	$ 17,866,726	$ 215,896	$ 331,038	$ (93,517)	$ 237,521	$ 18,104,247	1.33%
2	Small General Service	7	2,597	18,577,243	$ 2,022,821	$ (11,709)	$ 2,011,112	$ 21,909	$ 33,618	$ (10,568)	$ 23,049	$ 2,034,161	1.15%
3	Large General Secondary	9S	952	117,685,671	$ 9,567,264	$ (74,173)	$ 9,493,091	$ 138,782	$ 212,955	$ (66,970)	$ 145,985	$ 9,639,076	1.54%
4	Large General Primary	9P	5	15,372,234	$ 1,123,886	$ (9,380)	$ 1,114,506	$ 17,552	$ 26,932	$ 3,159	$ 30,091	$ 1,144,597	2.70%
5	Large General Transmission	9T	1	2,848,217	$ 192,531	$ (1,694)	$ 190,837	$ 3,173	$ 4,867	$ (1,471)	$ 3,395	$ 194,232	1.78%
6	Dusk to Dawn Lighting	15	0	432,863	$ 108,367	$ (273)	$ 108,094	$ 511	$ 784	$ (237)	$ 547	$ 108,641	0.51%
7	Large Power Primary	19P	6	168,443,209	$ 10,974,422	$ (102,627)	$ 10,871,795	$ 192,330	$ 294,956	$ (85,613)	$ 209,343	$ 11,081,138	1.93%
8	Large Power Transmission	19T	1	112,485,084	$ 6,816,226	$ (66,775)	$ 6,749,451	$ 125,167	$ 191,942	$ 141,481	$ 333,423	$ 7,082,874	4.94%
9	Agricultural Irrigation Service	24	2,025	67,579,536	$ 6,840,294	$ (42,588)	$ 6,797,706	$ 79,736	$ 122,325	$ (37,270)	$ 85,055	$ 6,882,761	1.25%
10	Unmetered General Service	40	2	5,388	$ 395	$ (3)	$ 392	$ 6	$ 10	$ (3)	$ 7	$ 399	1.74%
11	Street Lighting	41	26	890,836	$ 144,981	$ (562)	$ 144,419	$ 1,052	$ 1,613	$ 3,525	$ 5,139	$ 149,557	3.56%
12	Traffic Control Lighting	42	8	22,402	$ 2,175	$ (14)	$ 2,161	$ 26	$ 41	$ 66	$ 107	$ 2,268	4.94%
13	Total Uniform Tariffs		18,996	687,203,565	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ (147,418)	$ 1,073,662	$ 56,423,952	1.94%
14	Total Oregon Retail Sales		18,996	687,203,565	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ (147,418)	$ 1,073,662	$ 56,423,952	1.94%

(1) Updated June 2019-May 2020 Test Year

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	**3/1/2019**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**
2	**mc HL**	37.00	22.25	31.75	60.00	73.50	43.80	30.25	31.00	41.00	42.85	35.90	29.55
3	**mc LL**	29.00	14.60	14.00	33.15	39.25	31.45	24.70	25.75	33.20	32.65	28.60	23.50
4	**Reallocated Prices**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**
5	**HL PP**												
6	103.9%	38.44	23.12	32.99	62.34	76.37	45.51	31.43	32.21	42.60	44.52	37.30	30.70
7	**LL PP**												
8	107.1%	31.06	15.64	14.99	35.50	42.04	33.68	26.45	27.58	35.56	34.97	30.63	25.17
9	**HL SS**												
10	96.4%	35.67	21.45	30.61	57.84	70.85	42.22	29.16	29.88	39.52	41.31	34.61	28.49
11	**LL SS**												
12	93.4%	27.09	13.64	13.08	30.96	36.66	29.37	23.07	24.05	31.01	30.50	26.71	21.95

IPCO POWER SUPPLY EXPENSES FOR APRIL 1, 2019 -- MARCH 31, 2020 (One Hydro Condition)
Repriced Using UE 195 Settlement Methodology - 2019 March Forecast

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	1,214,177.5	1,169,085.7	833,524.5	599,345.3	548,513.4	434,986.2	452,285.4	372,904.0	464,806.8	713,750.4	711,968.4	838,047.4	8,353,394.9
	Bridger													
2	Energy (MWh)	-	-	28,608.8	357,583.1	358,788.5	236,935.5	154,621.7	213,707.8	302,459.6	256,559.9	113,418.2	20,982.2	2,043,665.3
3	AURORA Modeled Expense ($ x 1000)	$ -	$ -	$ 1,043.7	$ 12,094.4	$ 12,107.3	$ 8,112.4	$ 5,388.9	$ 7,389.4	$ 10,302.8	$ 8,137.1	$ 3,748.5	$ 709.7	$ 69,034.2
4	AURORA Modeled Handling Expense ($ x 1000)	$ -	$ -	$ 8.0	$ 100.1	$ 100.5	$ 66.3	$ 43.3	$ 59.8	$ 84.7	$ 71.8	$ 31.8	$ 5.9	$ 572.2
5	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ -	$ -	$ 1,035.7	$ 11,994.3	$ 12,006.8	$ 8,046.1	$ 5,345.6	$ 7,329.5	$ 10,218.1	$ 8,065.2	$ 3,716.8	$ 703.8	$ 68,462.0
6	IPC Share of OHAG Expense ($ x 1000)	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 261.0	$ 3,132.2
7	Total Expense ($ x 1000)	$ 261.0	$ 261.0	$ 1,296.7	$ 12,255.3	$ 12,267.9	$ 8,307.1	$ 5,606.6	$ 7,590.6	$ 10,479.1	$ 8,326.2	$ 3,977.8	$ 964.8	$ 71,594.2
	Boardman													
8	Energy (MWh)	2,483.2	1,610.9	20,660.9	39,706.9	39,527.6	32,402.4	27,691.5	30,616.0	39,706.9	31,292.3	15,663.4	7,874.8	289,236.7
9	AURORA Modeled Expense ($ x 1000)	$ 70.0	$ 49.8	$ 534.3	$ 1,004.4	$ 1,000.3	$ 821.9	$ 708.8	$ 777.2	$ 1,004.4	$ 905.7	$ 471.4	$ 249.4	$ 7,597.7
10	AURORA Modeled Handling Expense ($ x 1000)	$ 1.0	$ 0.7	$ 8.5	$ 16.3	$ 16.2	$ 13.3	$ 11.4	$ 12.6	$ 16.3	$ 12.8	$ 6.4	$ 3.2	$ 118.6
11	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 69.0	$ 49.2	$ 525.8	$ 988.2	$ 984.1	$ 808.6	$ 697.5	$ 764.6	$ 988.2	$ 892.8	$ 465.0	$ 246.2	$ 7,479.1
12	IPC Share of OHAG Expense ($ x 1000)	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 17.1	$ 205.3
13	Total Expense ($ x 1000)	$ 86.1	$ 66.3	$ 542.9	$ 1,005.3	$ 1,001.3	$ 825.7	$ 714.6	$ 781.7	$ 1,005.3	$ 910.0	$ 482.1	$ 263.3	$ 7,684.5
	Valmy													
14	Energy (MWh)	-	-	-	51,020.8	55,774.6	11,055.1	-	22,696.3	31,574.0	-	-	-	172,120.8
15	AURORA Modeled Expense ($ x 1000)	$ -	$ -	$ -	$ 1,957.5	$ 2,151.2	$ 459.8	$ -	$ 950.3	$ 1,277.3	$ -	$ -	$ -	$ 6,796.1
16	AURORA Modeled Handling Expense ($ x 1000)	$ -	$ -	$ -	$ 114.8	$ 125.5	$ 24.9	$ -	$ 51.1	$ 71.0	$ -	$ -	$ -	$ 387.3
17	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ -	$ -	$ -	$ 1,842.7	$ 2,025.7	$ 434.9	$ -	$ 899.2	$ 1,206.3	$ -	$ -	$ -	$ 6,408.8
18	IPC Share of OHAG Expense ($ x 1000)	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 310.2	$ 3,722.0
19	Usage Charges Paid to IPC ($ x 1000)	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 5.6	$ 67.4
20	Total Expense ($ x 1000)	$ 304.5	$ 304.5	$ 304.5	$ 2,147.3	$ 2,330.2	$ 739.5	$ 304.5	$ 1,203.7	$ 1,510.8	$ 304.5	$ 304.5	$ 304.5	$ 10,063.4
	Langley Gulch													
21	Energy (MWh)	29,942.8	168,746.9	186,895.3	199,049.8	198,737.9	193,607.5	180,519.2	181,804.2	197,956.2	174,227.4	155,721.1	148,535.8	2,015,744.0
22	Expense ($ x 1000)	$ 703.4	$ 2,869.3	$ 3,248.8	$ 4,232.3	$ 4,234.7	$ 3,930.4	$ 3,489.0	$ 4,345.1	$ 5,832.7	$ 4,999.1	$ 3,956.8	$ 3,254.4	$ 45,095.9
	Danskin													
23	Energy (MWh)	-	-	28,466.8	65,591.5	60,695.6	32,818.9	19,951.0	3,294.5	1,673.8	-	24.8	97.5	212,614.6
24	Expense ($ x 1000)	$ -	$ -	$ 824.9	$ 2,323.3	$ 2,156.3	$ 1,102.2	$ 633.7	$ 127.9	$ 79.5	$ -	$ 1.0	$ 3.5	$ 7,252.2
	Bennett Mountain													
25	Energy (MWh)	-	-	10,469.1	38,473.4	35,688.5	14,589.3	6,510.2	568.2	477.2	-	-	-	106,775.8
26	Expense ($ x 1000)	$ -	$ -	$ 306.5	$ 1,363.9	$ 1,267.7	$ 493.9	$ 210.0	$ 22.4	$ 23.0	$ -	$ -	$ -	$ 3,687.3
27	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 689.9	$ 712.5	$ 689.9	$ 712.5	$ 712.5	$ 689.9	$ 712.5	$ 689.9	$ 712.5	$ 711.2	$ 666.0	$ 711.2	$ 8,410.6
	Purchased Power (Excluding PURPA)													
28	Market Energy (MWh)	-	-	78,206.6	74,254.3	62,131.0	70,723.1	36,556.2	108,414.5	101,624.4	20,486.2	2,402.0	3,952.4	558,750.8
29	Elkhorn Wind Energy (MWh)	26,404.6	26,527.2	25,227.4	25,865.4	22,886.0	21,221.6	22,494.6	31,195.2	29,677.2	24,216.8	25,076.5	27,293.8	308,086.0
30	Neal Hot Springs Energy (MWh)	15,215.9	11,429.3	11,317.3	9,167.6	9,844.5	12,018.1	16,332.7	18,385.9	20,015.0	18,557.6	17,695.7	17,587.8	177,567.7
31	Raft River Geothermal Energy (MWh)	6,974.0	4,854.7	5,861.8	6,288.1	5,741.9	6,278.0	6,505.3	6,996.5	7,608.9	7,732.9	6,927.9	6,932.1	78,702.0
32	Total Energy Excl. PURPA (MWh)	48,594.5	42,811.1	120,613.2	115,575.5	100,603.3	110,240.8	81,888.8	164,992.0	158,925.5	70,993.4	52,102.2	55,766.1	1,123,106.5
33	Market Expense ($ x 1000)	$ -	$ -	$ 1,854.1	$ 3,412.3	$ 3,002.9	$ 2,769.3	$ 1,054.8	$ 3,229.7	$ 3,882.0	$ 766.6	$ 76.4	$ 99.9	20,148.0
34	Elkhorn Wind Expense ($ x 1000)	$ 1,247.9	$ 1,253.7	$ 1,622.1	$ 1,995.8	$ 1,765.9	$ 1,364.5	$ 1,446.4	$ 2,407.0	$ 2,289.9	$ 1,603.9	$ 1,660.8	$ 1,328.7	$ 19,986.5
35	Neal Hot Springs Expense ($ x 1000)	$ 1,298.8	$ 975.6	$ 1,317.9	$ 1,281.1	$ 1,375.7	$ 1,399.5	$ 1,901.9	$ 2,569.2	$ 2,796.9	$ 2,198.3	$ 2,096.2	$ 1,527.2	$ 20,738.4
36	Raft River Geothermal Expense ($ x 1000)	$ 345.4	$ 240.4	$ 395.0	$ 508.5	$ 464.3	$ 423.0	$ 438.3	$ 565.7	$ 615.3	$ 531.9	$ 476.6	$ 350.5	$ 5,354.8
37	Total Expense Excl. PURPA ($ x 1000)	$ 2,892.1	$ 2,469.7	$ 5,189.1	$ 7,197.6	$ 6,608.7	$ 5,956.3	$ 4,841.4	$ 8,771.7	$ 9,584.1	$ 5,100.7	$ 4,310.1	$ 3,306.2	$ 66,227.7
	Surplus Sales													
38	Energy (MWh)	489,417.3	403,281.0	32,273.2	17,063.9	49,186.7	11,865.1	20,375.2	5,898.8	9,032.7	20,751.6	93,057.4	166,683.0	1,318,885.8
39	Revenue Including Transmission Expenses ($ x 1000)	$ 15,909.4	$ 7,401.9	$ 804.0	$ 878.1	$ 3,188.1	$ 456.6	$ 521.5	$ 168.1	$ 334.5	$ 826.0	$ 3,022.4	$ 4,484.3	$ 37,995.0
40	Transmission Expenses ($ x 1000)	$ 489.4	$ 403.3	$ 32.3	$ 17.1	$ 49.2	$ 11.9	$ 20.4	$ 5.9	$ 9.0	$ 20.8	$ 93.1	$ 166.7	$ 1,318.9
41	Revenue Excluding Transmission Expenses ($ x 1000)	$ 15,420.0	$ 6,998.6	$ 771.7	$ 861.0	$ 3,138.9	$ 444.7	$ 501.2	$ 162.2	$ 325.5	$ 805.2	$ 2,929.4	$ 4,317.6	$ 36,676.1
	Net Hedges													
42	Energy (MWh)	-	-	22,400.0	50,400.0	70,824.0	-	-	-	-	-	-	-	143,624.0
43	Cost($ X 1000)	$ -	$ -	$ 347.2	$ 1,795.4	$ 4,214.1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,356.6
44	Net Power Supply Expenses ($ x 1000)	$ (10,483.0)	$ (315.3)	$ 11,978.9	$ 32,171.8	$ 31,654.3	$ 21,600.4	$ 16,011.2	$ 23,370.8	$ 28,901.5	$ 19,546.6	$ 10,768.9	$ 4,490.3	$ 189,696.4
45	PURPA ($ x 1000)	$ 18,142.7	$ 19,200.3	$ 23,471.5	$ 25,324.2	$ 23,342.1	$ 18,523.0	$ 16,375.6	$ 17,500.6	$ 16,357.7	$ 12,846.3	$ 15,541.2	$ 13,745.7	$ 220,371.1
46	EIM Benefits													$ 7,789.4
47	Total Net Power Supply Expenses ($ x 1000)	$ 7,659.7	$ 18,885.0	$ 35,450.4	$ 57,496.1	$ 54,996.4	$ 40,123.4	$ 32,386.8	$ 40,871.4	$ 45,259.2	$ 32,393.0	$ 26,310.1	$ 18,236.0	**$ 402,278.1**
48	Sales at Customer Level (In 000s MWH)	1,021.841	1,071.582	1,254.632	1,530.365	1,587.786	1,431.707	1,117.569	1,038.502	1,158.405	1,291.170	1,223.800	1,109.462	14,836.820
49	Hours in Month	720	744	720	744	744	720	744	720	744	744	696	744	8784
50	Unit Cost / MWH (for PCAM)	$7.50	$17.62	$28.26	$37.57	$34.64	$28.02	$28.98	$39.36	$39.07	$25.09	$21.50	$16.44	**$27.11**
	Prices Used in Purchased Power & Surplus Sales Above:													
	Heavy Load													
51	Portion of Purchased Power considered HL Purchases	0.00%	0.00%	48.42%	38.94%	18.34%	46.29%	48.22%	47.77%	37.53%	25.67%	17.78%	2.06%	
52	Purchased Power HL Price	38.44	23.12	32.99	62.34	76.37	45.51	31.43	32.21	42.60	44.52	37.30	30.70	
53	Portion of Surplus Sales considered HL Surplus Sales	63.17%	60.39%	67.51%	76.25%	82.34%	70.87%	41.49%	76.12%	70.80%	86.08%	73.04%	75.78%	
54	Surplus Sales HL Price	35.67	21.45	30.61	57.84	70.85	42.22	29.16	29.88	39.52	41.31	34.61	28.49	
	Light Load													
55	Portion of Purchased Power considered LL Purchases	0.00%	0.00%	51.58%	61.06%	81.66%	53.71%	51.78%	52.23%	62.47%	74.33%	82.22%	97.94%	
56	Purchased Power LL Price	31.06	15.64	14.99	35.50	42.04	33.68	26.45	27.58	35.56	34.97	30.63	25.17	
57	Portion of Surplus Sales considered LL Surplus Sales	36.83%	39.61%	32.49%	23.75%	17.66%	29.13%	58.51%	23.88%	29.20%	13.92%	26.96%	24.22%	
58	Surplus Sales LL Price	27.09	13.64	13.08	30.96	36.66	29.37	23.07	24.05	31.01	30.50	26.71	21.95	

IDAHO POWER COMPANY
YEAR OVER YEAR DIFFERENCES IN AURORA DEVELOPED NPSE
2019 MARCH FORECAST

	AURORA DEVELOPED NPSE RESULTS BEFORE MARKET ENERGY RE-PRICING			REPRICED USING FORWARD MARKET PRICES					DIFFERENCES			
	GENERATION			GENERATION					GENERATION			
		A	B		C	D	E	F	G	H	I	J
Line No.	Resource Type	2018 March Forecast	2019 March Forecast	Resource Type	2018 March Forecast		2019 March Forecast		(B-A)	(E-C)	(C-A)	(E-B)
1	Hydro (MWh)	8,511,525	8,353,395	Hydro (MWh)	8,511,525	52%	8,353,395	52%	(158,130)	(158,130)	-	-
2	Coal (MWh)	1,565,150	2,505,023	Coal (MWh)	1,565,150	10%	2,505,023	16%	939,873	939,873	-	-
3	Natural Gas (MWh)	3,364,548	2,335,134	Natural Gas (MWh)	3,364,548	21%	2,335,134	14%	(1,029,414)	(1,029,414)	-	-
4	Market Purchased Power (MWh)	645,373	702,375	Market Purchased Power (MWh)	645,373	4%	702,375	4%	57,002	57,002	-	-
5	Purchased Power Agreements (MWh)	543,697	564,356	Purchased Power Agreements (MWh)	543,697	3%	564,356	4%	20,658	20,658	-	-
6	PURPA (MWh)	2,889,715	2,967,158	PURPA (MWh)	2,889,715	18%	2,967,158	18%	77,443	77,443	-	-
7	Surplus Sales (MWh)	1,278,960	1,318,886	Surplus Sales (MWh)	1,278,960	-8%	1,318,886	-8%	39,926	39,926	-	-
8	System Generation (MWh)	17,520,008	17,427,441	System Generation (MWh)	17,520,008		17,427,441					
9	System Load (MWh)	16,241,049	16,108,555	System Load (MWh)	16,241,049	100%	16,108,555	100%	(132,494)	(132,494)	-	-
10	System Load (aMW)	1,854	1,834	System Load (aMW)	1,854		1,834		(20)	(20)	-	-

	NET POWER SUPPLY EXPENSES			NET POWER SUPPLY EXPENSES					NET POWER SUPPLY EXPENSES			
		A	B		C	D	E	F	G	H	I	J
Line No.	Resource Type	2018 March Forecast	2019 March Forecast	Resource Type	2018 March Forecast		2019 March Forecast		(B-A)	(E-C)	(C-A)	(E-B)
11	Hydro ($ x 1000)	$ -	$ -	Hydro ($ x 1000)	$ -		$ -		$ -	$ -	$ -	$ -
12	Coal ($ x 1000)	$ 58,508.1	$ 89,342.1	Coal ($ x 1000)	$ 58,508.1	15%	$ 89,342.1	22%	$ 30,834.0	$ 30,834.0	$ -	$ -
13	Natural Gas ($ x 1000)	$ 77,187.9	$ 64,446.0	Natural Gas ($ x 1000)	$ 77,187.9	20%	$ 64,446.0	16%	$ (12,741.9)	$ (12,741.9)	$ -	$ -
14	Market Purchased Power ($ x 1000)	$ 20,022.1	$ 24,710.4	Market Purchased Power ($ x 1000)	$ 14,938.0	4%	$ 26,504.6	7%	$ 4,688.3	$ 11,566.6	$ (5,084.1)	$ 1,794.2
15	Purchased Power Agreements ($ x 1000)	$ 43,024.4	$ 46,079.8	Purchased Power Agreements ($ x 1000)	$ 43,024.4	11%	$ 46,079.8	11%	$ 3,055.4	$ 3,055.4	$ -	$ -
16	PURPA ($ x 1000)	$ 210,568.1	$ 220,371.1	PURPA ($ x 1000)	$ 210,568.1	55%	$ 220,371.1	55%	$ 9,803.0	$ 9,803.0	$ -	$ -
17	Surplus Sales ($ x 1000)	$ (25,628.8)	$ (28,367.5)	Surplus Sales ($ x 1000)	$ (16,771.4)	-4%	$ (36,676.1)	-9%	$ (2,738.7)	$ (19,904.7)	$ 8,857.4	$ (8,308.6)
18	EIM Benefits	$ (5,500.0)	$ (7,789.4)	EIM Benefits	$ (5,500.0)	-1%	$ (7,789.4)	-2%	$ (2,289.4)	$ (2,289.4)	$ -	$ -
19	Total System ($ x 1000)	$ 378,181.8	$ 408,792.4	Total System ($ x 1000)	$ 381,955.0	100%	$ 402,278.1	100%	$ 30,610.7	$ 20,323.0	$ 3,773.3	$ (6,514.4)

Idaho Power Company
2019 APCU
Oregon Jurisdictional EIM Revenue Requirement

2019 Calendar Year Revenue Requirement

Capital Investment	$353,712
ADIT	($9,176)
Accumulated Depreciation	($1,468)
Amortization of Other Plant	($39,471)
Net Rate Base	$303,597
Return on Rate Base	**$23,550**
O&M (On-going)	$34,429
Depreciation	$49,385
Taxes	($24,692)
Total Operating Expenses	**$59,122**
Net-to-Gross Tax Multiplier	1.347
Total Revenue Requirement	**$111,328**

APCU Combined Rate Calculation
April 2019 - March 2020

Line		
	OCTOBER APCU	
1	Forecast of Normalized Sales (MWh)	14,836,820
2	Total Net Power Supply Expense	$384,156,490
3	October APCU Unit Cost ($/MWh)	$25.89
	MARCH FORECAST	
4	Forecast of Normalized Sales (MWh)	14,836,820
5	Total Net Power Supply Expense	$402,278,053
6	March Forecast Unit Cost ($/MWh)	$27.11
7	Sales Adjusted Forecast Power Cost Change	$18,100,920
8	Portion of Change Allowed	95%
9	Forecast Change Allowed	$17,195,874
10	**March Forecast Rate ($/MWh)**	$1.16
11	**Combined Rate ($/MWh)**	$27.05

Idaho Power Company
Stipulated Revenue Spread
2019 October Update

Line No.		
1	2019 October Update Oregon Jurisdictional Share of Base NPSE = $25.89/MWh x 686,328,238 MWhs =	$ 17,769,038
2	Oregon Allocated EIM Costs	$ 111,328
3	**Proposed October Update APCU Revenue Requirement**	**$ 17,880,366**

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)
4	**April 2019 - March 2020 Generation Level Normalized Sales (kWh)**	**739,054,443**	200,415,527	20,337,588	128,830,884	16,293,835	2,945,056	474,418	178,538,874	116,192,364	74,019,084	5,904	976,356	24,553
5	**Class Share of April 2019 - March 2020 Generation Level Normalized Sales (kWh)**	**100%**	27.12%	2.75%	17.43%	2.20%	0.40%	0.06%	24.16%	15.72%	10.02%	0.00%	0.13%	0.00%
6	**2019 October Update Class Allocated Base NPSE**	$ 17,880,366	$ 4,848,767	$ 492,039	$ 3,116,879	$ 394,206	$ 71,251	$ 11,478	$ 4,319,493	$ 2,811,108	$ 1,790,786	$ 143	$ 23,622	$ 594
7	**June 2019 - May 2020 Loss-Adjusted Normalized Sales (kWh)**	**687,203,565**	182,860,882	18,577,243	117,685,671	15,372,234	2,848,217	432,863	168,443,209	112,485,084	67,579,536	5,388	890,836	22,402
8	**Proposed APCU Base Rates for 2019 October Update ($/kWh)**	**0.026019**	**0.026516**	**0.026486**	**0.026485**	**0.025644**	**0.025016**	**0.026516**	**0.025644**	**0.024991**	**0.026499**	**0.026511**	**0.026516**	**0.026517**
9	**Proposed October Update APCU Revenue Requirement**	**$ 17,880,366**	$ 4,848,767	$ 492,039	$ 3,116,879	$ 394,206	$ 71,251	$ 11,478	$ 4,319,493	$ 2,811,108	$ 1,790,786	$ 143	$ 23,622	$ 594

Line No.														
10	**Current APCU Base Rates for 2018 October Update ($/kWh) - Order No. 18-170**	**0.026284**	0.027402	0.027429	0.027428	0.025801	0.025886	0.027439	0.026514	0.021840	0.027425	0.027433	0.022934	0.022111
11	**June 2019 - May 2020 Loss-Adjusted Normalized Sales (kWh)**	**687,203,565**	182,860,882	18,577,243	117,685,671	15,372,234	2,848,217	432,863	168,443,209	112,485,084	67,579,536	5,388	890,836	22,402
12	**Base NPSE Recovered under Current APCU Base Rates**	**$ 18,027,784**	$ 5,010,833	$ 509,563	$ 3,227,913	$ 396,620	$ 73,730	$ 11,877	$ 4,466,172	$ 2,456,630	$ 1,853,372	$ 148	$ 20,430	$ 495

Idaho Power Company
Revenue Spread Exhibit for 2019 APCU March Forecast
Stipulated Revenue Spread

Line No.		
1	Oregon Jurisdictional Share of 2019 March Forecast NPSE = $1.16/MWh x 686,328.238 MWhs =	$ 796,141

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 2019 - March 2020 Generation Level Normalized Sales (kWh)	739,054,443	200,415,527	20,337,588	128,830,884	16,293,835	2,945,056	474,418	178,538,874	116,192,364	74,019,084	5,904	976,356	24,553
3	Class Share of April 2019 - March 2020 Generation Level Normalized Sales (kWh)	100%	27.12%	2.75%	17.43%	2.20%	0.40%	0.06%	24.16%	15.72%	10.02%	0.00%	0.13%	0.00%
4	2019 March Forecast Class Allocated NPSE	$ 796,141	$ 215,896	$ 21,909	$ 138,782	$ 17,552	$ 3,173	$ 511	$ 192,330	$ 125,167	$ 79,736	$ 6	$ 1,052	$ 26
5	June 2019 - May 2020 Loss-Adjusted Normalized Sales (kWh)	687,203,565	182,860,882	18,577,243	117,685,671	15,372,234	2,848,217	432,863	168,443,209	112,485,084	67,579,536	5,388	890,836	22,402
6	Proposed APCU Rates for 2019 March Forecast ($/kWh)	0.00116	0.00118	0.00118	0.00118	0.00114	0.00111	0.00118	0.00114	0.00111	0.00118	0.00118	0.00118	0.00118
7	Proposed March Forecast Revenue Requirement	$ 796,141	$ 215,896	$ 21,909	$ 138,782	$ 17,552	$ 3,173	$ 511	$ 192,330	$ 125,167	$ 79,736	$ 6	$ 1,052	$ 26

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)
8	APCU Rates for 2018 March Forecast - Order No. 18-170 ($/kWh)	(0.00062)	(0.00063)	(0.00063)	(0.00063)	(0.00061)	(0.00059)	(0.00063)	(0.00061)	(0.00059)	(0.00063)	(0.00063)	(0.00063)	(0.00063)
9	June 2019 - May 2020 Loss-Adjusted Normalized Sales (kWh)	687,203,565	182,860,882	18,577,243	117,685,671	15,372,234	2,848,217	432,863	168,443,209	112,485,084	67,579,536	5,388	890,836	22,402
10	NPSE Recovered under Current March Forecast Rate	$ (424,940)	$ (115,142)	$ (11,709)	$ (74,173)	$ (9,380)	$ (1,694)	$ (273)	$ (102,627)	$ (66,775)	$ (42,588)	$ (3)	$ (562)	$ (14)

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2019

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 Base Revenue w/o NPSE	Current Base NPSE Revenue	Total Current Base Revenue	Proposed Base NPSE Revenue	Total Proposed Base Revenue	Proposed Adjustments to Base Revenue	Percent Change Base to Base Revenue
	Uniform Tariff Rates:										
1	Residential Service	1	13,373	182,860,882	$ 12,912,980	$ 5,010,833	$ 17,923,813	$ 4,848,767	$ 17,761,747	$ (162,066)	(0.90)%
2	Small General Service	7	2,597	18,577,243	$ 1,513,267	$ 509,563	$ 2,022,830	$ 492,039	$ 2,005,306	$ (17,524)	(0.87)%
3	Large General Secondary	9S	952	117,685,671	$ 6,339,412	$ 3,227,913	$ 9,567,325	$ 3,116,879	$ 9,456,291	$ (111,034)	(1.16)%
4	Large General Primary	9P	5	15,372,234	$ 727,274	$ 396,620	$ 1,123,893	$ 394,206	$ 1,121,480	$ (2,414)	(0.21)%
5	Large General Transmission	9T	1	2,848,217	$ 118,803	$ 73,730	$ 192,533	$ 71,251	$ 190,054	$ (2,479)	(1.29)%
6	Dusk to Dawn Lighting	15	0	432,863	$ 96,490	$ 11,877	$ 108,367	$ 11,478	$ 107,968	$ (399)	(0.37)%
7	Large Power Primary	19P	6	168,443,209	$ 6,508,337	$ 4,466,172	$ 10,974,509	$ 4,319,493	$ 10,827,830	$ (146,679)	(1.34)%
8	Large Power Transmission	19T	1	112,485,084	$ 4,359,654	$ 2,456,630	$ 6,816,284	$ 2,811,108	$ 7,170,763	$ 354,479	5.20%
9	Agricultural Irrigation Service	24	2,025	67,579,536	$ 4,986,957	$ 1,853,372	$ 6,840,329	$ 1,790,786	$ 6,777,743	$ (62,587)	(0.91)%
10	Unmetered General Service	40	2	5,388	$ 248	$ 148	$ 395	$ 143	$ 390	$ (5)	(1.26)%
11	Street Lighting	41	26	890,836	$ 124,551	$ 20,430	$ 144,981	$ 23,622	$ 148,172	$ 3,191	2.20%
12	Traffic Control Lighting	42	8	22,402	$ 1,680	$ 495	$ 2,175	$ 594	$ 2,274	$ 99	4.54%
13	Total Uniform Tariffs		18,996	687,203,565	$ 37,689,651	$ 18,027,784	$ 55,717,436	$ 17,880,366	$ 55,570,017	$ (147,418)	(0.26)%
14	Total Oregon Retail Sales		18,996	687,203,565	$ 37,689,651	$ 18,027,784	$ 55,717,436	$ 17,880,366	$ 55,570,017	$ (147,418)	(0.26)%

Line No	Tariff Description	Current Billed Revenue w/o March Forecast	Current Billed March Forecast Revenue	Total Current Billed Revenue	Proposed March Forecast Revenue	Proposed Adjustments to March Forecast Revenue	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Percent Change Billed to Billed Revenue	Stipulated Revenue Increase Cap (4.94%)	Revenue Requirement Shortfall
	Uniform Tariff Rates:										
1	Residential Service	$ 17,981,868	$ (115,142)	$ 17,866,726	$ 215,896	$ 331,038	$ 168,973	$ 18,035,698	0.95%	$ 168,973	$ -
2	Small General Service	$ 2,022,821	$ (11,709)	$ 2,011,112	$ 21,909	$ 33,618	$ 16,093	$ 2,027,205	0.80%	$ 16,093	$ -
3	Large General Secondary	$ 9,567,264	$ (74,173)	$ 9,493,091	$ 138,782	$ 212,955	$ 101,921	$ 9,595,012	1.07%	$ 101,921	$ -
4	Large General Primary	$ 1,123,886	$ (9,380)	$ 1,114,506	$ 17,552	$ 26,932	$ 24,518	$ 1,139,024	2.20%	$ 24,518	$ -
5	Large General Transmission	$ 192,531	$ (1,694)	$ 190,837	$ 3,173	$ 4,867	$ 2,388	$ 193,225	1.25%	$ 2,388	$ -
6	Dusk to Dawn Lighting	$ 108,367	$ (273)	$ 108,094	$ 511	$ 784	$ 385	$ 108,479	0.36%	$ 385	$ -
7	Large Power Primary	$ 10,974,422	$ (102,627)	$ 10,871,795	$ 192,330	$ 294,956	$ 148,277	$ 11,020,072	1.36%	$ 148,277	$ -
8	Large Power Transmission	$ 6,816,226	$ (66,775)	$ 6,749,451	$ 125,167	$ 191,942	$ 546,421	$ 7,295,872	8.10%	$ 333,423	$ 212,998
9	Agricultural Irrigation Service	$ 6,840,294	$ (42,588)	$ 6,797,706	$ 79,736	$ 122,325	$ 59,738	$ 6,857,444	0.88%	$ 59,738	$ -
10	Unmetered General Service	$ 395	$ (3)	$ 392	$ 6	$ 10	$ 5	$ 397	1.22%	$ 5	$ -
11	Street Lighting	$ 144,981	$ (562)	$ 144,419	$ 1,052	$ 1,613	$ 4,805	$ 149,224	3.33%	$ 4,805	$ -
12	Traffic Control Lighting	$ 2,175	$ (14)	$ 2,161	$ 26	$ 41	$ 139	$ 2,301	6.44%	$ 107	$ 33
13	Total Uniform Tariffs	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ 1,073,662	$ 56,423,952	1.94%	$ 860,632	$ 213,030
14	Total Oregon Retail Sales	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ 1,073,662	$ 56,423,952	1.94%		

(1) Updated June 2019-May 2020 Test Year

Idaho Power Company
Revenue Spread Exhibit for 2019 APCU
Stipulated Revenue Spread

Line No.			
1	4.94% Increase Cap - Revenue Requirement Shortfall	$ 213,030	

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 2019 - March 2020 Generation Level Normalized Sales (kWh)**	**622,837,526**	200,415,527	20,337,588	128,830,884	16,293,835	2,945,056	474,418	178,538,874		74,019,084	5,904	976,356	
3	**Class Share of April 2019 - March 2020 Generation Level Normalized Sales (kWh)**	**100%**	32.18%	3.27%	20.68%	2.62%	0.47%	0.08%	28.67%		11.88%	0.00%	0.16%	
4	**2019 APCU Class Allocated Revenue Requirement Shortfall**	**$ 213,030**	$ 68,548	$ 6,956	$ 44,064	$ 5,573	$ 1,007	$ 162	$ 61,066		$ 25,317	$ 2	$ 334	
5	**June 2019 - May 2020 Loss-Adjusted Normalized Sales (kWh)**	**574,696,079**	182,860,882	18,577,243	117,685,671	15,372,234	2,848,217	432,863	168,443,209		67,579,536	5,388	890,836	
6	**2019 APCU Revenue Requirement Shortall Rates ($/kWh)**	**0.00037**	**0.00037**	**0.00037**	**0.00037**	**0.00036**	**0.00035**	**0.00037**	**0.00036**		**0.00037**	**0.00037**	**0.00037**	

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2019

Summary of Revenue Impact
Current Base Revenue to Proposed Base Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers	Normalized Energy (kWh)	Current Base Revenue w/o NPSE	Current Base NPSE Revenue	Total Current Base Revenue	Proposed Base NPSE Revenue	Total Proposed Base Revenue	Proposed Adjustments to Base Revenue	Percent Change Base to Base Revenue	1st Pass Adjustment to Proposed Base NPSE Revenue	1st Pass Proposed Adjustments to Base Revenue	1st Pass Percent Change Base to Base Revenue	1st Pass Proposed Base NPSE Revenue	Revised APCU Rates for 2019 October Update ($/kWh)
	Uniform Tariff Rates:															
1	Residential Service	1	13,373	182,860,882	$ 12,912,980	$ 5,010,833	$ 17,923,813	$ 4,848,767	$ 17,761,747	$ (162,066)	(0.90)%	$ 68,548	$ (93,517)	(0.52)%	$ 4,917,316	0.026891
2	Small General Service	7	2,597	18,577,243	$ 1,513,267	$ 509,563	$ 2,022,830	$ 492,039	$ 2,005,306	$ (17,524)	(0.87)%	$ 6,956	$ (10,568)	(0.52)%	$ 498,995	0.026861
3	Large General Secondary	9S	952	117,685,671	$ 6,339,412	$ 3,227,913	$ 9,567,325	$ 3,116,879	$ 9,456,291	$ (111,034)	(1.16)%	$ 44,064	$ (66,970)	(0.70)%	$ 3,160,943	0.026859
4	Large General Primary	9P	5	15,372,234	$ 727,274	$ 396,620	$ 1,123,893	$ 394,206	$ 1,121,480	$ (2,414)	(0.21)%	$ 5,573	$ 3,159	0.28%	$ 399,779	0.026007
5	Large General Transmission	9T	1	2,848,217	$ 118,803	$ 73,730	$ 192,533	$ 71,251	$ 190,054	$ (2,479)	(1.29)%	$ 1,007	$ (1,471)	(0.76)%	$ 72,259	0.025370
6	Dusk to Dawn Lighting	15	0	432,863	$ 96,490	$ 11,877	$ 108,367	$ 11,478	$ 107,968	$ (399)	(0.37)%	$ 162	$ (237)	(0.22)%	$ 11,640	0.026891
7	Large Power Primary	19P	6	168,443,209	$ 6,508,337	$ 4,466,172	$ 10,974,509	$ 4,319,493	$ 10,827,830	$ (146,679)	(1.34)%	$ 61,066	$ (85,613)	(0.78)%	$ 4,380,559	0.026006
8	Large Power Transmission	19T	1	112,485,084	$ 4,359,654	$ 2,456,630	$ 6,816,284	$ 2,811,108	$ 7,170,763	$ 354,479	5.20%	$ -	$ 141,481	2.08%	$ 2,598,110	0.023097
9	Agricultural Irrigation Service	24	2,025	67,579,536	$ 4,986,957	$ 1,853,372	$ 6,840,329	$ 1,790,786	$ 6,777,743	$ (62,587)	(0.91)%	$ 25,317	$ (37,270)	(0.54)%	$ 1,816,103	0.026874
10	Unmetered General Service	40	2	5,388	$ 248	$ 148	$ 395	$ 143	$ 390	$ (5)	(1.26)%	$ 2	$ (3)	(0.75)%	$ 145	0.026885
11	Street Lighting	41	26	890,836	$ 124,551	$ 20,430	$ 144,981	$ 23,622	$ 148,172	$ 3,191	2.20%	$ 334	$ 3,525	2.43%	$ 23,955	0.026891
12	Traffic Control Lighting	42	8	22,402	$ 1,680	$ 495	$ 2,175	$ 594	$ 2,274	$ 99	4.54%	$ -	$ 66	3.04%	$ 562	0.025066
13	Total Uniform Tariffs		18,996	687,203,565	$ 37,689,651	$ 18,027,784	$ 55,717,436	$ 17,880,366	$ 55,570,017	$ (147,418)	(0.26)%	$ 213,030	$ (147,418)	(0.26)%	$ 17,880,366	
14	Total Oregon Retail Sales		18,996	687,203,565	$ 37,689,651	$ 18,027,784	$ 55,717,436	$ 17,880,366	$ 55,570,017	$ (147,418)	(0.26)%	$ 213,030	$ (147,418)	(0.26)%	$ 17,880,366	

(1) Updated June 2019-May 2020 Test Year

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2019

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 w/o March Forecast	Current Billed March Forecast Revenue	Total Current Billed Revenue	Proposed March Forecast Revenue	Proposed Adjustments to March Forecast Revenue	Proposed Adjustments to Base Revenue	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:												
1	Residential Service	1	13,373	182,860,882	$ 17,981,868	$ (115,142)	$ 17,866,726	$ 215,896	$ 331,038	$ (93,517)	$ 237,521	$ 18,104,247	1.33%
2	Small General Service	7	2,597	18,577,243	$ 2,022,821	$ (11,709)	$ 2,011,112	$ 21,909	$ 33,618	$ (10,568)	$ 23,049	$ 2,034,161	1.15%
3	Large General Secondary	9S	952	117,685,671	$ 9,567,264	$ (74,173)	$ 9,493,091	$ 138,782	$ 212,955	$ (66,970)	$ 145,985	$ 9,639,076	1.54%
4	Large General Primary	9P	5	15,372,234	$ 1,123,886	$ (9,380)	$ 1,114,506	$ 17,552	$ 26,932	$ 3,159	$ 30,091	$ 1,144,597	2.70%
5	Large General Transmission	9T	1	2,848,217	$ 192,531	$ (1,694)	$ 190,837	$ 3,173	$ 4,867	$ (1,471)	$ 3,395	$ 194,232	1.78%
6	Dusk to Dawn Lighting	15	0	432,863	$ 108,367	$ (273)	$ 108,094	$ 511	$ 784	$ (237)	$ 547	$ 108,641	0.51%
7	Large Power Primary	19P	6	168,443,209	$ 10,974,422	$ (102,627)	$ 10,871,795	$ 192,330	$ 294,956	$ (85,613)	$ 209,343	$ 11,081,138	1.93%
8	Large Power Transmission	19T	1	112,485,084	$ 6,816,226	$ (66,775)	$ 6,749,451	$ 125,167	$ 191,942	$ 141,481	$ 333,423	$ 7,082,874	4.94%
9	Agricultural Irrigation Service	24	2,025	67,579,536	$ 6,840,294	$ (42,588)	$ 6,797,706	$ 79,736	$ 122,325	$ (37,270)	$ 85,055	$ 6,882,761	1.25%
10	Unmetered General Service	40	2	5,388	$ 395	$ (3)	$ 392	$ 6	$ 10	$ (3)	$ 7	$ 399	1.74%
11	Street Lighting	41	26	890,836	$ 144,981	$ (562)	$ 144,419	$ 1,052	$ 1,613	$ 3,525	$ 5,139	$ 149,557	3.56%
12	Traffic Control Lighting	42	8	22,402	$ 2,175	$ (14)	$ 2,161	$ 26	$ 41	$ 66	$ 107	$ 2,268	4.94%
13	Total Uniform Tariffs		18,996	687,203,565	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ (147,418)	$ 1,073,662	$ 56,423,952	1.94%
14	Total Oregon Retail Sales		18,996	687,203,565	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ (147,418)	$ 1,073,662	$ 56,423,952	1.94%

(1) Updated June 2019-May 2020 Test Year

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2019

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 w/o March Forecast	Current Billed March Forecast Revenue	Total Current Billed Revenue	Proposed March Forecast Revenue	Proposed Adjustments to March Forecast Revenue	Proposed Adjustments to Base Revenue	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:												
1	Residential Service	1	13,373	182,860,882	$ 17,981,868	$ (115,142)	$ 17,866,726	$ 215,896	$ 331,038	$ (93,517)	$ 237,521	$ 18,104,247	1.33%
2	Small General Service	7	2,597	18,577,243	$ 2,022,821	$ (11,709)	$ 2,011,112	$ 21,909	$ 33,618	$ (10,568)	$ 23,049	$ 2,034,161	1.15%
3	Large General Secondary	9S	952	117,685,671	$ 9,567,264	$ (74,173)	$ 9,493,091	$ 138,782	$ 212,955	$ (66,970)	$ 145,985	$ 9,639,076	1.54%
4	Large General Primary	9P	5	15,372,234	$ 1,123,886	$ (9,380)	$ 1,114,506	$ 17,552	$ 26,932	$ 3,159	$ 30,091	$ 1,144,597	2.70%
5	Large General Transmission	9T	1	2,848,217	$ 192,531	$ (1,694)	$ 190,837	$ 3,173	$ 4,867	$ (1,471)	$ 3,395	$ 194,232	1.78%
6	Dusk to Dawn Lighting	15	0	432,863	$ 108,367	$ (273)	$ 108,094	$ 511	$ 784	$ (237)	$ 547	$ 108,641	0.51%
7	Large Power Primary	19P	6	168,443,209	$ 10,974,422	$ (102,627)	$ 10,871,795	$ 192,330	$ 294,956	$ (85,613)	$ 209,343	$ 11,081,138	1.93%
8	Large Power Transmission	19T	1	112,485,084	$ 6,816,226	$ (66,775)	$ 6,749,451	$ 125,167	$ 191,942	$ 141,481	$ 333,423	$ 7,082,874	4.94%
9	Agricultural Irrigation Service	24	2,025	67,579,536	$ 6,840,294	$ (42,588)	$ 6,797,706	$ 79,736	$ 122,325	$ (37,270)	$ 85,055	$ 6,882,761	1.25%
10	Unmetered General Service	40	2	5,388	$ 395	$ (3)	$ 392	$ 6	$ 10	$ (3)	$ 7	$ 399	1.74%
11	Street Lighting	41	26	890,836	$ 144,981	$ (562)	$ 144,419	$ 1,052	$ 1,613	$ 3,525	$ 5,139	$ 149,557	3.56%
12	Traffic Control Lighting	42	8	22,402	$ 2,175	$ (14)	$ 2,161	$ 26	$ 41	$ 66	$ 107	$ 2,268	4.94%
13	Total Uniform Tariffs		18,996	687,203,565	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ (147,418)	$ 1,073,662	$ 56,423,952	1.94%
14	Total Oregon Retail Sales		18,996	687,203,565	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ (147,418)	$ 1,073,662	$ 56,423,952	1.94%

(1) Updated June 2019-May 2020 Test Year