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April 8, 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 Supplemental 2019 March Forecast Testimony (Idaho Power/300-307).

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

SUPPLEMENTAL DIRECT TESTIMONY

OF

MARK A. ANNIS

April 8, 2019

Q. Please state your name, business address and present occupation.

A. My name is Mark A. Annis. I am employed by Idaho Power Company ("Idaho Power" or "Company") as a Senior Regulatory Analyst in the Regulatory Affairs department. My business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. Please describe your educational background.

A. I earned a Bachelor of Arts degree in Business Administration (accounting emphasis) from the University of South Dakota in May 1984. That year I also passed the Uniform Certified Public Accounting ("CPA") exam and am currently a licensed CPA in the state of Idaho. I have also attended electric utility ratemaking and financial courses, including "Introduction to Rate Design and Cost of Service" presented by Electric Utilities Consultants, Inc.

Q. **Please describe your business experience with Idaho Power.**

A. I began my employment with Idaho Power in 1997 in the Company's Finance department as an Accountant II, where I performed a variety of general and corporate accounting duties, with a focus on external reporting and accounting research. Over the next 18 years I held several other positions within the Finance department, including Business Analyst II, Technical Research Coordinator, External Reporting Team Leader, and Financial Reporting and Accounting Research Manager. In these positions I was responsible for a variety of tasks, including researching accounting policy issues and implementing new accounting standards, including Federal Energy Regulatory Commission ("FERC") accounting and reporting issues, completing the Company's quarterly and annual reports filed with the Securities and Exchange Commission, reviewing FERC Form 1, and analyzing financial statements.

In May 2016 I accepted a position as the Budget and Revenue Manager in the Finance department. In this position I acted as a liaison between the Regulatory

Affairs and Finance departments, as well as overseeing aspects of the Company's budgeting processes.

In March 2017, I went on a temporary duty assignment in the Regulatory Affairs department, and in March 2018 I transitioned full-time to Regulatory Affairs as a Senior Regulatory Analyst. As a Regulatory Analyst, I provide support for the Company's various regulatory activities, including regulatory ratemaking and compliance filings.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Company's updated forecast of benefits related to participation in the Western Energy Imbalance Market ("EIM"), replacing and supplementing the benefits forecast included in the initial March 25, 2018, filing.[1] My testimony will also detail the revised proposed rates resulting from the Company's update to the EIM benefits forecast. It is important to note that no other changes have been made to any other elements of net power supply expense ("NPSE") included in the March forecast, and therefore, discussion of those other elements is not repeated in this testimony.

Q. What is the status of 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.

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[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).

On March 25, 2019, the Company filed the 2019 March Forecast containing a preliminary forecast of EIM benefits for the upcoming April 2019 through March 2019 time period. At that time, the Company indicated that it was still finalizing its forecast of benefits related to EIM participation, and that its final quantification would be completed and filed as supplemental testimony within two weeks of March 25, 2018.

On April 4, 2019, the Company, Staff, and CUB participated in a Settlement Conference. Following the Settlement Conference, Idaho Power conferred with CUB and Staff with regard to modifying the procedural schedule of this case to allow more time for Staff and CUB to review Idaho Power's supplemental testimony to be filed April 8, 2019. After reaching agreement with Staff and CUB, Idaho Power filed a "Motion to Modify Procedural Schedule" on April 5, 2019, which was approved on April 8, 2019. This motion extended the date for Staff and CUB's initial March Forecast testimony from April 10, 2019, to April 24, 2019.

Q. How is your testimony organized?

A. My testimony presents the Company's updated EIM benefit forecast for the 2019 Annual Power Cost Update ("APCU"), detailing each of the forecast adjustments the Company made to develop an accurate quantification of expected benefits over the April 2019 through March 2020 time period. My testimony then provides an updated quantification of the projected revenue requirement increase and the proposed rate implementation to allocate the revenue increase to customers.

Q. Are you updating any of the exhibits previously filed in this proceeding?

A. Yes, I am providing the following exhibits, which update those included in the Company's March 25, 2019, March Forecast filing:

1. Exhibit 301, determination of expected NPSE for the 2019 March Forecast.

2. Exhibit 302, determination of normalized NPSE for the 2019 October Update.
3. Exhibit 303, year-over-year differences in modeled NPSE.
4. Exhibit 304, October Update and March Forecast combined rate calculation.
5. Exhibit 305, revenue spread.
6. Exhibit 306, calculation of revenue impact.

Q. Are you introducing any new exhibits?

A. Yes, I'm introducing Exhibit 307, which details the calculation of the Company's EIM benefits forecast.

I. EIM COSTS AND BENEFITS

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

A. Idaho Power is proposing to include $11.93 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 $0.55 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 initially on the California Independent System Operator ("CAISO") report of EIM benefits. As discussed in Idaho Power's initial March Forecast testimony, the Company identified several issues with the CAISO's method of calculating EIM benefits and has been actively working with Power Settlements and CAISO to shadow and validate CAISO's benefit calculation. Previous testimony describes the shadow calculations and corrections to the CAISO methodology resulting from this process. After review of the CAISO methodology, the Company determined that additional adjustments are necessary to develop an appropriate adjustment to the Company's modeled NPSE that reasonably reflects the ongoing cost savings benefits associated with Idaho Power's participation in the EIM. These adjustments, which I will detail individually, include an adjustment to the CAISO methodology as it pertains to the hydro pricing cost structure, an adjustment to forecasted Greenhouse Gas ("GHG") payments,[2] and an adjustment for third-party load included in the Company's balancing area. The Direct Testimony of Nicole A. Blackwell previously filed in this matter on March 25, 2019, identified each of these issues as requiring further analysis.

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

A. As discussed in the testimony of Ms. Blackwell filed on March 25, 2019, CAISO agreed to correct its counterfactual ("CF") modeling assumption for all EIM entities on a going-forward basis. This correction was based on an invalid assumption utilized by CAISO associated with using the transfer price as a floor, as detailed on pages 18 through 20 of Ms. Blackwell's testimony.

Q. What were the results of this correction to CAISO's methodology?

CAISO 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. Due to the administrative burden, CAISO chose not to re-run or re-publish prior quarters' Western EIM Benefits Reports for Idaho Power, but did agree to re-run one month from the second and third quarters of 2018 with the corrected

[2] Idaho Power bids all of its participating resources (hydro, coal, and natural gas generation) into the EIM. To the extent any of this generation is imported into California, Idaho Power receives GHG payments from the EIM to reimburse the cost of Carbon Allowances required by California to offset emissions from this generation. In the case of hydro resources where there are no carbon emissions, these payments are revenue without associated Carbon Allowance obligations, and therefore, all these payments are used to reduce net power supply costs.

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 month of June. 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 for the month of August. These revised CAISO EIM benefit amounts were not published publicly but were provided to Idaho Power for informational purposes.

Q. Did Idaho Power incorporate these revised calculations in its Company-developed EIM benefits calculation?

A. Yes. Using the CAISO reported EIM benefits as a starting point, Idaho Power's first step in calculating its own EIM benefit estimate was to extrapolate the monthly reductions in CAISO-stated EIM benefits for the months of June and August 2018 for the entire second and third quarters of 2018. Specifically, Idaho Power applied the 28 percent reduction identified for the June 2018 benefits uniformly to each of the remaining months in the second quarter, which resulted in a revised second quarter EIM benefits amount of $5.6 million compared to the $7.8 million published by CAISO. Idaho Power also uniformly applied the 30 percent reduction identified for the August 2018 benefits to the entire third quarter, which resulted in a revised third quarter EIM benefits amount of $9.3 million compared to the $13.3 million published by CAISO.

At the time of this filing, the first quarter 2019 CAISO benefits report is not yet available. However, the Company performed a shadow calculation and validated the CAISO benefit results for January 2019, which included CAISO's corrected modeling methodology related to CF bid costs and determined that CAISO's EIM benefit calculation of $1.6 million appropriately reflected the agreed-upon methodology changes as included in the quarterly revisions by CAISO. Because CAISO has not yet published the first quarter 2019 results, Idaho Power then applied the January

2019 CAISO EIM benefit estimate to the remaining months of the first quarter of 2019, resulting in a total first quarter 2019 benefit estimate of $4.9 million. Using these results, Idaho Power estimated an annual EIM benefits amount of $25.6 million using the corrected CAISO methodology. The derivation of this amount is presented on Exhibit 307, columns A-C. As previously stated, this amount requires three additional adjustments to develop an accurate forecast of EIM benefits for Idaho Power in the context of an adjustment to modeled NPSE. These adjustments are reflected in columns D through H of Exhibit 307 and consist of a hydro pricing adjustment, a GHG benefits adjustment, and a third-party load adjustment.

Q. Please describe the adjustment related to the hydro pricing cost structure.

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 a zero-variable cost resource, Idaho Power bids hydro resources based on an operational value rather than the actual 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.

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 FERC'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.[3] 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

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

prevent flow of more water than allowed during a particular timeframe. 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.

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, not economics. The CF calculation incorrectly reflects the tier price as the avoided cost for hydro (as zero cost resources) thereby overstating the resulting benefits.

Q. How did Idaho Power adjust CAISO's EIM benefit calculation to reflect the economic value of hydro rather than the bid price?

A. Prior to joining the EIM, Idaho Power had three hydro tiers that identified the value of water made available to PSM for market sales. The first tier was typically utilized during spill conditions and was given the lowest price by the PSM. The second tier included energy posted to the PSM that could be sold, required no immediate replacement, and had minimal impacts on operations. The third tier reflected energy that could be sold by the PSM but would likely require the purchase of replacement energy in a future period and was given a higher price by the PSM. Prior to joining the EIM, the second and third tiers were utilized most of the hours under normal operating conditions.

When the Company joined the EIM, the three existing tiers were maintained and designated as INC Tiers 1, 2, and 3, and three additional tiers were established, INC Tiers 4, 5, and 6, to provide additional granularity for EIM dispatch decisions. INC Tiers 4, 5, and 6 were created to allow the operators to reflect more extreme market and system conditions where any EIM dispatches of the water in those tiers could potentially have significant negative operational and reliability impacts. These tiers are typically used by operators to meet target reservoir elevations needed to meet future load serving requirements and to optimize the water for future generating hours. Thus, the PSM's pricing for INC Tiers 4, 5, or 6 reflects the operational value – not the dispatch cost – of the water to Idaho Power. As such, the Company determined that for purposes of the EIM benefit calculation to serve as an adjustment to modeled NPSE, all tiers should be replaced with a zero cost for hydro resources.

Q. Did Idaho Power replace the higher tier prices reflected in CAISO's benefit calculation for all months?

A. No. In Idaho Power's shadow calculation, it replaced the tier prices reflected in CAISO's benefit calculation for all months of the fourth quarter with a zero cost. By doing so, the revised EIM benefits were $2.5 million, which is a $3.3 million or 56 percent reduction to CAISO's fourth quarter EIM benefit of $5.8 million.

Because Idaho Power's trial period with Power Settlements began in mid-September 2018, there is a lack of bid data available to shadow the CAISO benefit calculation prior to October 2018. As a result, Idaho Power could not input revised costs into the shadow calculation to determine a revised benefit for the third quarter. However, because system conditions in the third quarter of 2018 were similar to conditions in the fourth quarter, the Company applied the 56 percent reduction due to replacing hydro bids in all tiers with zero prices identified for the fourth quarter to CAISO's benefit calculation for the third quarter. This resulted in a revised third quarter EIM benefit estimate of $4.1 million, which is $5.2 million less than the CAISO third quarter EIM benefit of $9.3 million.

Additionally, at the time of this filing, CAISO benefits data was not available for most of the first quarter, and the Company was not participating in the EIM in the first quarter of 2018. However, Idaho Power was able to make an adjustment to the hydro pricing structure for January 2019 which resulted in a revised estimate of $1.2 million, which is a $451 thousand or 27 percent reduction from the CAISO January benefit result of $1.6 million. Because Idaho Power did not have final numbers for February or March 2019, the Company applied the 27 percent reduction to the remaining months of the first quarter, resulting in a revised first quarter benefit estimate of $3.6 million, down 1.4 million from the estimated first quarter benefit of $4.9 million.

Because system conditions were similar between the first and second quarters, and due to a lack of bid data available for the second quarter as mentioned above, the Company also applied the 27 percent reduction due to replacing hydro bids in all tiers with zero prices identified for January 2019, to CAISO's benefit calculation for the second quarter. This resulted in a revised second quarter EIM benefit estimate of $4.1 million, which is $1.5 million less than the CAISO second quarter EIM benefit of $5.6 million.

Q. What are the resulting benefits after correcting for the hydro pricing structure?

A. After applying the more accurate hydro pricing structure to CAISO's benefit calculations, Idaho Power's estimate of EIM benefits is $14.3 million. The impact of this change in methodology can be seen in columns D through E of Exhibit 307.

Q. Please explain the change in the CAISO's procedures related to GHG payments.

A. On November 1, 2018, CAISO implemented changes that were approved by FERC to revise its EIM bid adder rules by adding language to its tariff that limits the hourly dispatchable bid range between the resource's base schedule and its effective upper economic bid for the relevant operating hour. CAISO stated this will more accurately attribute energy produced by EIM participating resources, because it will limit the amount of a resource's output that can be designated as supporting a transfer into CAISO when the resource has already been scheduled to serve load outside of CAISO. CAISO further stated that the proposal reflects that capacity associated with base schedules in advance of the real-time market is effectively committed to serve EIM load and to meet specific resource sufficiency tests, and that this commitment creates a base from which the market can determine what incremental capacity a resource has available to serve load in the CAISO or another EIM Entity balancing authority areas located within California. Since the GHG bid quantity is now limited and the EIM dispatch will identify other participating resources that have available capacity above their base schedule to support EIM transfers into CAISO, Idaho Power expects a reduced financial benefit from net GHG revenues related to selling electricity to CAISO.

Q. Please describe the adjustment to reduce the GHG benefits resulting from the Company's participation in the EIM.

A. The Company made a forecast adjustment to expected EIM benefits for the April 2019 through March 2020 forecast period related to GHG benefits. The Company reduced the estimate of GHG revenues to include in the 2019 APCU forecast by $1,530,114, as shown in column F of Exhibit 307. Idaho Power's actual GHG benefits for the prior year were approximately $4.7 million, with the final forecast amount of GHG revenues included in the 2019 APCU forecast of EIM benefits revised to $3.2 million.[4]

In estimating GHG awards for the 2019 APCU test period, for the forecast months of November 2019 through March 2020, the Company used prior year actual results, as actuals in these months already reflected the change by CAISO to limit the

[4] Please note, on page 24 of Ms. Blackwell's testimony filed March 25, 2019, Idaho Power discussed the inclusion of $3.3 million in net GHG benefits in the 2019 APCU. Due to do the availability of additional data since the time of that filing, this testimony includes an updated net GHG benefits forecast of $3.2 million.

GHG bid quantity. 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 revenues are significantly lower due to low market GHG allowance prices. For the forecast months of July through October, the Company reduced prior year actuals based on observed differences in actual GHG benefits subsequent to the change in CAISO's GHG payment procedure, as shown in column G of Exhibit 307.

Q. Previous testimony indicated that Idaho Power has concerns that benefits related to third-party loads in the Company's balancing area authority ("BAA") are included in CAISO's benefit calculation. Please explain.

A. As explained in the prior testimony, the benefits reported by CAISO reflect a value for the entire BAA each month. However, 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, the Company developed 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.

Q. Please describe the adjustment to allocate a portion of the EIM benefits to third-party load.

A. The Company applied the monthly percentage of transmission load ratio share attributable to its third-party load customer for April 2018 through February 2019. Since March 2019 was not available at the time of this filing, the Company used the load ratio share for February and applied this to March. This calculation determined that on average, approximately 7.25 percent of the BAA load relates to the third parties. In order to only include EIM benefits related to the Company, the EIM benefit was reduced by $803,519, which reflects the 7.25 percent of the total BAA EIM benefits.

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

A. The Company's EIM benefits forecast is based on the CAISO's revised EIM benefits reports, with adjustments to the CF methodology described in previous testimony, as well as necessary adjustments for hydro pricing, GHG benefits, and third-party loads as described in this testimony. As detailed in Exhibit 307, the Company's total estimated benefit for the April 2019 through March 2020 time period is $11.9 million, or $0.55 million on an Oregon jurisdictional basis.

The Company's estimate of EIM benefits is reflected as an offset to forecast NPSE for the March Forecast, as shown in Exhibit 301. The Company has also included the estimate of EIM benefits as an offset to forecast NPSE for the October Update, as shown in Exhibit 302. 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 $11.9 million, normalized NPSE included in the October Update totals $380.0 million.

Q. As it gains more experience operating within the EIM, are there any other areas of the benefits forecast methodology the Company will continue to investigate for possible use in future filings?

A. Yes. The Company will continue to evaluate the potential need to normalize the forecast for any anomalies that may have existed during the historical base period. These potential adjustments could correct for abnormal factors such as weather, water, and market conditions.

II. PER-UNIT COST CALCULATION AND QUANTIFICATION OF THE REVENUE REQUIREMENT IMPACT.

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 $398.1 million, or $16.2 million more than the 2018 March Forecast of NPSE of $382.0 million.[5] The initial March Forecast proposed a revenue increase of $1.07 million or a 1.94 percent increase. If the March Forecast and October Update are approved as proposed in this filing, the 2019 composite APCU (both the October Update and March Forecast components) will result in a revenue increase of $0.88 million or a 1.59 percent increase, to become effective June 1, 2019.

Q. What is the revised March Forecast unit cost per megawatt-hour ("MWh") for this filing?

A. Exhibit 301 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 $26.83 per MWh ($398.1 million / 14.837 million MWh = $26.83 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 $26.83 per MWh.

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

A. Exhibit 304 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 $25.61 per MWh. Lines 4-6 show the calculation for the March Forecast unit cost of $26.83 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

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

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 305, 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 $0.34 million, or 0.61 percent. Exhibit 305 contains the revised October Update revenue requirement.

III. 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 1.59 percent; therefore, any rate increases applied to individual customer classes will be capped at 4.59 percent. The proposed revenue spread resulting from the application of the stipulated methodology is shown in Exhibit 305.

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 306 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 306, the overall revenue impact of this year's combined October Update and March Forecast is an increase of $0.88 million or 1.59 percent overall. The $0.88 million increase reflects a decrease of $0.34 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.

Idaho Power/301
Witness: Mark A. Annis

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 350
MARCH FORECAST

Exhibit Accompanying Supplemental Testimony of Mark A. Annis

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

April 8, 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													$ 11,929.3
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	**$ 398,138.1**
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	**$26.83**
	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	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 350
MARCH FORECAST

Exhibit Accompanying Supplemental Testimony of Mark A. Annis

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

April 8, 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													$ 11,929.3
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	**$ 380,016.567**
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	**$25.61**
	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 Supplemental Testimony of Mark A. Annis

Year-Over-Year March Forecast Comparison

April 8, 2019

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
	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	12%	$ 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)	$ (11,929.3)	EIM Benefits	$ (5,500.0)	-1%	$ (11,929.3)	-3%	$ (6,429.3)	$ (6,429.3)	$ -	$ -
19	Total System ($ x 1000)	$ 378,181.8	$ 404,652.5	Total System ($ x 1000)	$ 381,955.0	100%	$ 398,138.1	100%	$ 26,470.7	$ 16,183.1	$ 3,773.3	$ (6,514.4)

Idaho Power/304
Witness: Mark A. Annis

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 350
MARCH FORECAST

Exhibit Accompanying Supplemental Testimony of Mark A. Annis

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

April 8, 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	$	380,016,567
3	October APCU Unit Cost ($/MWh)	$	25.61
	MARCH FORECAST		
4	Forecast of Normalized Sales (MWh)		14,836,820
5	Total Net Power Supply Expense	$	398,138,113
6	March Forecast Unit Cost ($/MWh)	$	26.83
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)**	$	26.77

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 350
MARCH FORECAST

Exhibit Accompanying Supplemental Testimony of Mark A. Annis

Revenue Spread for October Update and March Forecast

April 8, 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 =	$ 17,576,866
2	Oregon Allocated EIM Costs	$ 111,328
3	**Proposed October Update APCU Revenue Requirement**	**$ 17,688,194**

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**	$ 17,688,194	$ 4,796,654	$ 486,751	$ 3,083,380	$ 389,969	$ 70,486	$ 11,355	$ 4,273,069	$ 2,780,895	$ 1,771,539	$ 141	$ 23,368	$ 588
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 ($/kWh)**	**0.025739**	**0.026231**	**0.026201**	**0.026200**	**0.025368**	**0.024747**	**0.026231**	**0.025368**	**0.024722**	**0.026214**	**0.026226**	**0.026231**	**0.026232**
9	**Proposed October Update APCU Revenue Requirement**	**$ 17,688,194**	$ 4,796,654	$ 486,751	$ 3,083,380	$ 389,969	$ 70,486	$ 11,355	$ 4,273,069	$ 2,780,895	$ 1,771,539	$ 141	$ 23,368	$ 588

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.														
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	$ 4,796,654	$ 17,709,634	$ (214,179)	(1.19)%	$ 17,981,868	$ (115,142)	$ 17,866,726	$ 215,896	$ 331,038	$ 116,860	$ 17,983,585	0.65%	$ 116,860	$ -
2	Small General Service	7	2,597	18,577,243	1,513,267	509,563	2,022,830	486,751	2,000,018	(22,813)	(1.13)%	2,022,821	(11,709)	2,011,112	21,909	33,618	10,805	2,021,917	0.54%	10,805	-
3	Large General Secondary	9S	952	117,685,671	6,339,412	3,227,913	9,567,325	3,083,380	9,422,792	(144,533)	(1.51)%	9,567,264	(74,173)	9,493,091	138,782	212,955	68,422	9,561,513	0.72%	68,422	-
4	Large General Primary	9P	5	15,372,234	727,274	396,620	1,123,893	389,969	1,117,243	(6,651)	(0.59)%	1,123,886	(9,380)	1,114,506	17,552	26,932	20,281	1,134,787	1.82%	20,281	-
5	Large General Transmission	9T	1	2,848,217	118,803	73,730	192,533	70,486	189,288	(3,245)	(1.69)%	192,531	(1,694)	190,837	3,173	4,867	1,622	192,459	0.85%	1,622	-
6	Dusk to Dawn Lighting	15	0	432,863	96,490	11,877	108,367	11,355	107,845	(523)	(0.48)%	108,367	(273)	108,094	511	784	261	108,355	0.24%	261	-
7	Large Power Primary	19P	6	168,443,209	6,508,337	4,466,172	10,974,509	4,273,069	10,781,405	(193,103)	(1.76)%	10,974,422	(102,627)	10,871,795	192,330	294,956	101,853	10,973,648	0.94%	101,853	-
8	Large Power Transmission	19T	1	112,485,084	4,359,654	2,456,630	6,816,284	2,780,895	7,140,550	324,266	4.76%	6,816,226	(66,775)	6,749,451	125,167	191,942	516,208	7,265,659	7.65%	309,800	206,408
9	Agricultural Irrigation Service	24	2,025	67,579,536	4,986,957	1,853,372	6,840,329	1,771,539	6,758,496	(81,833)	(1.20)%	6,840,294	(42,588)	6,797,706	79,736	122,325	40,491	6,838,197	0.60%	40,491	-
10	Unmetered General Service	40	2	5,388	248	148	395	141	389	(7)	(1.65)%	395	(3)	392	6	10	3	395	0.83%	3	-
11	Street Lighting	41	26	890,836	124,551	20,430	144,981	23,368	147,918	2,937	2.03%	144,981	(562)	144,419	1,052	1,613	4,551	148,970	3.15%	4,551	-
12	Traffic Control Lighting	42	8	22,402	1,680	495	2,175	588	2,268	92	4.24%	2,175	(14)	2,161	26	41	133	2,294	6.15%	99	34
13	Total Uniform Tariffs		18,996	687,203,565	$ 37,689,651	$18,027,784	$55,717,436	$17,688,194	$ 55,377,845	$ (339,590)	(0.61)%	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ 881,490	$ 56,231,780	1.59%	$ 675,048	$ 206,442
14	Total Oregon Retail Sales		18,996	687,203,565	$ 37,689,651	$18,027,784	$55,717,436	$17,688,194	$ 55,377,845	$ (339,590)	(0.61)%	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ 881,490	$ 56,231,780	1.59%		

(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	$ 206,442

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**	**$ 206,442**	$ 66,428	$ 6,741	$ 42,701	$ 5,401	$ 976	$ 157	$ 59,177		$ 24,534	$ 2	$ 324	
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)**	**0.00036**	**0.00036**	**0.00036**	**0.00036**	**0.00035**	**0.00034**	**0.00036**	**0.00035**		**0.00036**	**0.00036**	**0.00036**	

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	$ 4,796,654	$ 17,709,634	$ (214,179)	(1.19)%	$ 66,428	$ (147,750)	(0.82)%	$ 4,863,083	0.026594
2	Small General Service	7	2,597	18,577,243	1,513,267	509,563	2,022,830	486,751	2,000,018	(22,813)	(1.13)%	6,741	(16,072)	(0.79)%	493,492	0.026564
3	Large General Secondary	9S	952	117,685,671	6,339,412	3,227,913	9,567,325	3,083,380	9,422,792	(144,533)	(1.51)%	42,701	(101,832)	(1.06)%	3,126,081	0.026563
4	Large General Primary	9P	5	15,372,234	727,274	396,620	1,123,893	389,969	1,117,243	(6,651)	(0.59)%	5,401	(1,250)	(0.11)%	395,370	0.025720
5	Large General Transmission	9T	1	2,848,217	118,803	73,730	192,533	70,486	189,288	(3,245)	(1.69)%	976	(2,268)	(1.18)%	71,462	0.025090
6	Dusk to Dawn Lighting	15	0	432,863	96,490	11,877	108,367	11,355	107,845	(523)	(0.48)%	157	(365)	(0.34)%	11,512	0.026594
7	Large Power Primary	19P	6	168,443,209	6,508,337	4,466,172	10,974,509	4,273,069	10,781,405	(193,103)	(1.76)%	59,177	(133,926)	(1.22)%	4,332,246	0.025719
8	Large Power Transmission	19T	1	112,485,084	4,359,654	2,456,630	6,816,284	2,780,895	7,140,550	324,266	4.76%	-	117,858	1.73%	2,574,487	0.022887
9	Agricultural Irrigation Service	24	2,025	67,579,536	4,986,957	1,853,372	6,840,329	1,771,539	6,758,496	(81,833)	(1.20)%	24,534	(57,299)	(0.84)%	1,796,073	0.026577
10	Unmetered General Service	40	2	5,388	248	148	395	141	389	(7)	(1.65)%	2	(5)	(1.15)%	143	0.026589
11	Street Lighting	41	26	890,836	124,551	20,430	144,981	23,368	147,918	2,937	2.03%	324	3,261	2.25%	23,691	0.026594
12	Traffic Control Lighting	42	8	22,402	1,680	495	2,175	588	2,268	92	4.24%	-	59	2.70%	554	0.024728
13	Total Uniform Tariffs		18,996	687,203,565	$ 37,689,651	$ 18,027,784	$ 55,717,436	$ 17,688,194	$ 55,377,845	$ (339,590)	(0.61)%	$ 206,442	$ (339,590)	(0.61)%	$ 17,688,194	
14	Total Oregon Retail Sales		18,996	687,203,565	$ 37,689,651	$ 18,027,784	$ 55,717,436	$ 17,688,194	$ 55,377,845	$ (339,590)	(0.61)%	$ 206,442	$ (339,590)	(0.61)%	$ 17,688,194	

(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	$ (147,750)	$ 183,288	$ 18,050,014	1.03%
2	Small General Service	7	2,597	18,577,243	2,022,821	(11,709)	2,011,112	21,909	33,618	(16,072)	17,546	2,028,658	0.87%
3	Large General Secondary	9S	952	117,685,671	9,567,264	(74,173)	9,493,091	138,782	212,955	(101,832)	111,123	9,604,214	1.17%
4	Large General Primary	9P	5	15,372,234	1,123,886	(9,380)	1,114,506	17,552	26,932	(1,250)	25,682	1,140,188	2.30%
5	Large General Transmission	9T	1	2,848,217	192,531	(1,694)	190,837	3,173	4,867	(2,268)	2,598	193,435	1.36%
6	Dusk to Dawn Lighting	15	0	432,863	108,367	(273)	108,094	511	784	(365)	419	108,513	0.39%
7	Large Power Primary	19P	6	168,443,209	10,974,422	(102,627)	10,871,795	192,330	294,956	(133,926)	161,030	11,032,825	1.48%
8	Large Power Transmission	19T	1	112,485,084	6,816,226	(66,775)	6,749,451	125,167	191,942	117,858	309,800	7,059,251	4.59%
9	Agricultural Irrigation Service	24	2,025	67,579,536	6,840,294	(42,588)	6,797,706	79,736	122,325	(57,299)	65,025	6,862,731	0.96%
10	Unmetered General Service	40	2	5,388	395	(3)	392	6	10	(5)	5	397	1.33%
11	Street Lighting	41	26	890,836	144,981	(562)	144,419	1,052	1,613	3,261	4,874	149,293	3.38%
12	Traffic Control Lighting	42	8	22,402	2,175	(14)	2,161	26	41	59	99	2,261	4.59%
13	Total Uniform Tariffs		18,996	687,203,565	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ (339,590)	$ 881,490	$ 56,231,780	1.59%
14	Total Oregon Retail Sales		18,996	687,203,565	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ (339,590)	$ 881,490	$ 56,231,780	1.59%

(1) Updated June 2019-May 2020 Test Year

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 350
MARCH FORECAST

Exhibit Accompanying Supplemental Testimony of Mark A. Annis

Summary of Revenue Impact

April 8, 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	$ (147,750)	$ 183,288	$ 18,050,014	1.03%
2	Small General Service	7	2,597	18,577,243	2,022,821	(11,709)	2,011,112	21,909	33,618	(16,072)	17,546	2,028,658	0.87%
3	Large General Secondary	9S	952	117,685,671	9,567,264	(74,173)	9,493,091	138,782	212,955	(101,832)	111,123	9,604,214	1.17%
4	Large General Primary	9P	5	15,372,234	1,123,886	(9,380)	1,114,506	17,552	26,932	(1,250)	25,682	1,140,188	2.30%
5	Large General Transmission	9T	1	2,848,217	192,531	(1,694)	190,837	3,173	4,867	(2,268)	2,598	193,435	1.36%
6	Dusk to Dawn Lighting	15	0	432,863	108,367	(273)	108,094	511	784	(365)	419	108,513	0.39%
7	Large Power Primary	19P	6	168,443,209	10,974,422	(102,627)	10,871,795	192,330	294,956	(133,926)	161,030	11,032,825	1.48%
8	Large Power Transmission	19T	1	112,485,084	6,816,226	(66,775)	6,749,451	125,167	191,942	117,858	309,800	7,059,251	4.59%
9	Agricultural Irrigation Service	24	2,025	67,579,536	6,840,294	(42,588)	6,797,706	79,736	122,325	(57,299)	65,025	6,862,731	0.96%
10	Unmetered General Service	40	2	5,388	395	(3)	392	6	10	(5)	5	397	1.33%
11	Street Lighting	41	26	890,836	144,981	(562)	144,419	1,052	1,613	3,261	4,874	149,293	3.38%
12	Traffic Control Lighting	42	8	22,402	2,175	(14)	2,161	26	41	59	99	2,261	4.59%
13	Total Uniform Tariffs		18,996	687,203,565	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ (339,590)	$ 881,490	$ 56,231,780	1.59%
14	Total Oregon Retail Sales		18,996	687,203,565	$ 55,775,229	$ (424,940)	$ 55,350,290	$ 796,141	$ 1,221,080	$ (339,590)	$ 881,490	$ 56,231,780	1.59%

(1) Updated June 2019-May 2020 Test Year

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 350
MARCH FORECAST

Exhibit Accompanying Supplemental Testimony of Mark A. Annis

EIM Benefits

April 8, 2019

IDAHO POWER COMPANY
CALCULATION OF ENERGY IMBALANCE MARKET BENEFITS
2019 OCTOBER UPDATE / MARCH FORECAST

A

			A	B	C	D	E	F	G	H
			CAISO Original	**CAISO Methodology Adjustments**	**CAISO Revised**	**Zero-Priced Hydro Adjustment**	**Adjusted Balance**	**GHG Benefits Adjustment**	**Third Party Load**	**Net EIM Benefit**
1		Oct-18	$ 4,583,970	$ 2,574,175	$ 2,009,795	$ (993,214)	$ 1,016,582	$ (317,497)	$ (64,195)	$ 634,889
2	Q4	Nov-18	2,970,586	1,273,159	1,697,427	(1,131,846)	565,582	27,397	(12,095)	580,884
3		Dec-18	2,820,096	711,955	2,108,141	(1,156,246)	951,895	30,539	(28,456)	953,978
			$ 10,374,652	$ 4,559,288	$ 5,815,364	$ (3,281,305)	$ 2,534,059	$ (259,561)	$ (104,746)	$ 2,169,752
4		Jul-18	$ 4,548,038	$ 1,364,411	$ 3,183,626	$ (1,782,831)	$ 1,400,796	$ (429,363)	$ (86,381)	$ 885,052
5	Q3	Aug-18	6,358,596	1,928,596	4,430,000	(2,480,800)	1,949,200	(514,297)	(123,543)	1,311,359
6		Sep-18	2,398,642	719,592	1,679,049	(940,267)	738,782	(441,592)	(36,846)	260,343
			$ 13,305,275	$ 4,012,599	$ 9,292,675	$ (5,203,898)	$ 4,088,777	$ (1,385,253)	$ (246,770)	$ 2,456,754
7		Apr-18	$ 2,570,000	$ 719,600	$ 1,850,400	$ (499,608)	$ 1,350,792	$ 342	$ (96,294)	$ 1,254,840
8	Q2	May-18	2,540,000	711,200	1,828,800	(493,776)	1,335,024	1,047	(94,789)	1,241,282
9		Jun-18	2,640,000	740,000	1,900,000	(513,000)	1,387,000	6,995	(94,172)	1,299,823
			$ 7,750,000	$ 2,170,800	$ 5,579,200	$ (1,506,384)	$ 4,072,816	$ 8,384	$ (285,255)	$ 3,795,945
10		Jan-19	$ 1,640,110	$ -	$ 1,640,110	$ (451,005)	$ 1,189,106	$ 22,319	$ (53,878)	$ 1,157,547
11	Q1	Feb estimated	-	-	1,640,110	(451,005)	1,189,106	46,533	(50,561)	1,185,077
12		March estimated	-	-	1,640,110	(451,005)	1,189,106	37,464	(62,308)	1,164,261
13			$ 1,640,110	$ -	$ 4,920,330	$ (1,353,014)	$ 3,567,317	$ 106,316	$ (166,747)	$ 3,506,886
	Total		**$ 33,070,037**	**$ 10,742,687**	**$ 25,607,570**	**$ (11,344,601)**	**$ 14,262,969**	**$ (1,530,114)**	**$ (803,519)**	**$ 11,929,336**

Estimated from the previous month
Published Results