ORDER NO. 18 170

ENTERED: MAY 21 2018

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 333

In the Matter of IDAHO POWER COMPANY 2018 Annual Power Cost Update.	ORDER

DISPOSITION: STIPULATION ADOPTED; ANNUAL POWER COST UPDATE APPROVED

We adopt the stipulation of the parties and approve Idaho Power Company's Annual Power Cost Update (APCU). The APCU updates the company's net power supply expenses and results in new rates to go into effect June 1, 2018.

I. INTRODUCTION

In Order No. 08-238, we approved an automatic adjustment clause for Idaho Power that allows the company to annually update its net power supply expense (NPSE) included in rates. The APCU is comprised of two components: an October Update and a March Forecast. The October Update contains the company's forecasted net power supply expense reflected on a normalized and unit basis for an April through March test period. The March Forecast contains the company's net power supply expenses based on updated actual forecast conditions. The APCU mechanism allows for the rates from the October Update and March Forecast to become effective on June 1 of each year.

II. PROCEDURAL HISTORY

On October 31, 2017, Idaho Power filed testimony and exhibits for its 2018 APCU, including the October Update which estimated what the normal power supply expenses would be for the 12-month test year, April 2018 through March 2019.[1] As more fully discussed below, Staff filed opening testimony on February 12, 2018, and Idaho Power filed reply testimony on March 1, 2018. The Oregon Citizens Utility Board also filed reply testimony on March 1, 2018. The company subsequently filed the March Forecast

[1] Idaho Power/100-109.

on March 23, 2018. The testimony filed by each party is received as evidence in this docket.

Following discovery, the filing of testimony and settlement discussions, on May 1, 2018, the company, CUB and Staff of the Oregon Public Utility Commission (Staff) filed a stipulation, attached as Appendix A, settling all of the outstanding issues between the parties. Also on May 1, 2018, the parties filed a Joint Explanatory Brief in support of their stipulation.

III. THE 2018 APCU

A. The October Update

Idaho Power's 2018 October Update addressed the following variables: (1) fuel prices and transportation costs, (2) wheeling expenses, (3) planned outages and forced outage rates, (4) heat rates, (5) forecast of normalized load and normalized sales, (6) contracts for wholesale power and power purchases and sales, (7) forward price curve, (8) Public Utility Regulatory Policies Act of 1978 (PURPA) expenses, and (9) the Oregon state allocation factor.[2]

The October Update included the company's estimate of incremental costs and benefits associated with participating in the western Energy Imbalance Market (EIM) to be included in the 2018 APCU. The company proposed to set estimated EIM benefits equal to EIM costs.[3]

Idaho Power's calculations resulted in a cost per unit of $26.54 per megawatt-hour (MWh), an increase of 1.8 percent over last year's October update price of $26.06 per MWh.[4] For the 2018 October Update, the company calculated the Oregon jurisdictional share of total NPSE by multiplying the cost per unit of $26.54 per MWh by the forecasted Oregon jurisdictional loss-adjusted normalized sales for the April through March test period, consistent with the methodology approved in the 2017 stipulation. Idaho Power then calculated the incremental Oregon jurisdictional NPSE by comparing the 2018 October Update Oregon jurisdictional share of total NPSE to the NPSE recovery under current approved rates from the 2017 APCU October Update, resulting in an incremental revenue requirement of $360,109.[5] The company's revenue spread methodology for the 2018 October Update allocated the incremental revenue requirement

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[2] See *Id.*
[3] Idaho Power/100, Blackwell/14-16.
[4] *Id.* at 17.
[5] Idaho Power/200, Blackwell/17.

to individual customer classes on the basis of normalized jurisdictional forecasted sales at the generation level for the test period.[6]

On February 12, 2018, Commission Staff filed opening testimony and exhibits. Staff's testimony raised concerns related to the following: (1) the method used by the company to allocate costs between Oregon rate classes; (2) the recovery of depreciation expense for plant owned by Bridger Coal Company (BCC); (3) Idaho Power's fueling plan for the Jim Bridger Plant (Bridger); (4) Idaho Power's proposal for the recovery of costs – including capital costs – related to its participation in the EIM; and (5) Idaho Power's accounting for the costs related to purchases from qualified facilities (QFs) under PURPA. CUB did not file opening testimony.

On March 1, 2018, Idaho Power filed reply testimony and responded to the issues raised in Staff's opening testimony.[7] The company supported its rate spread and allocation proposals, estimates of PURPA costs, and its request to recover EIM costs. In addition, the company supported its BCC costs, including its method for calculating the depreciable lives of BCC assets.

CUB also filed reply testimony on March 1, 2018. CUB's testimony focused on a single issue, arguing that the APCU is not the appropriate mechanism by which Idaho Power should recover capital costs related to the EIM.[8]

B. The 2018 March Forecast

On March 23, 2018, Idaho Power filed the 2018 March Forecast component of the APCU. The March Forecast consisted of direct testimony with respect to the company's estimate of the expected NPSE for the April 2017—March 2018 water year.[9]

In its March Forecast, the company reviewed all the variables for the March Forecast and the following variables changed since the 2018 October Update: (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 recent water supply forecast from the Northwest River Forecast Center and current reservoir levels, (5) known power purchases and surplus sales made in compliance with the company's energy risk management policy, (6) forward price curve and (7) PURPA contract expenses.[10]

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[6] Idaho Power/100, Blackwell/20; Idaho Power/108, Blackwell/1.
[7] See Idaho Power/200 and 300.
[8] CUB/100, Gehrke/3.
[9] Idaho Power/300-305.
[10] Idaho Power/400, Blackwell/4.

Among the more significant factors the 2017 March Forecast addressed were the following:

- ***Fuel Price Update***: The per-unit cost of generation for the Boardman plant decreased 12 percent between the October Update and March Forecast. The per-unit cost of generation increased at Bridger and Valmy.[11]

- ***Hydro forecast Update***: Idaho Power reports that expected inflows and flood control targets are forecast to keep flows generally within power plant capacity through the spring, resulting in a similar generation estimate as compared to last year.[12] Hydro generation in the March forecast represents a 0.12 million MWh decrease as compared to the October Update.

- ***PURPA Generation***: The 2018 March Forecast estimated 331 aMW in PURPA generation, which was 1 aMW lower than projected in the October Update, reflecting a decrease in PURPA expense of 3 percent compared to the October Update.[13]

- ***EIM Costs and Benefits Update:*** On an Oregon allocated basis, the revenue requirement associated with EIM costs is $133,268, which represented an increase of $31,748 over the October Update estimate.[14]

The company calculated a March forecast rate of negative $0.59 per MWh, as compared to last year's March Forecast rate of $0.24 per MWh.[15] The overall proposed revenue impact of the combined October and March rates was a decrease of $0.22 million, or a 0.39 percent decrease overall.[16] The 2018 March

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[11] *Id.* at 5-6.
[12] *Id.* at 8-9.
[13] *Id.* at 8.
[14] *Id.* at 14-15.
[15] *Id.* at 16.
[16] *Id.* at 18.

Forecast also included the company's proposed rate spread used to spread the March Forecast revenue requirement to the various customer classes.[17]

IV. THE STIPULATION

The parties agree that the Commission should adopt the APCU for Idaho Power subject to certain changes in the current filing as agreed upon in the stipulation. The parties agree that the results are in conformance with the methodology set forth in Order No. 08-238 and Order No. 10-191, and that rates produced are fair, just, and reasonable. They ask that the terms of the stipulation should be made effective on June 1, 2018, as permitted by the APCU mechanism, with a revenue requirement decrease of $376,324.

The key provisions of the stipulation are as follows:

1. Idaho Power will adopt a modified rate spread methodology. Under the proposed modified methodology, the Oregon jurisdictional share of total NPSE, instead of the Oregon jurisdictional share of incremental NPSE, will be allocated to individual customer classes on the basis of normalized jurisdictional forecasted sales at the generation level for the forecast April through March test period. Any rate increases resulting from the application of this methodology as applied to a customer class will be limited to three percent above the overall average rate increase on a percentage of total revenue basis.

2. No later than July 31, 2018, Idaho Power will provide to the stipulating parties analysis of the long-term fueling plan for Bridger. As part of that analysis, Idaho Power will compare the costs of Options A and B.

3. In future APCU filings, Idaho Power will include information setting forth how and why BCC depreciation expense has changed from the levels set the company's most recent general rate case. Idaho Power will provide workpapers in future APCU filings to support the depreciable lives of Bridger Coal Company assets. The parties will work together to determine the types of workpapers to be included in future APCU filings prior to the filing of the 2019 APUC in October 2018.

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[17] *Id.* at 15-16; Idaho Power/403, Blackwell/1.

4. Idaho Power will implement adjustments to the PURPA forecast included in the March Forecast of the APCU, beginning with the 2018 APCU March Forecast. First, for any new PURPA project expected to come online during the APCU forecast test period, the forecast generation and expense will be included in the forecast beginning in the month in which the project is expected to come online. Second, the expected online date for any new PURPA project will be adjusted using the three-year average Contract Delay Rate (CDR) of historical PURPA projects. The CDR is based on the average of differences in scheduled operation date and actual operation date for historical PURPA projects.

5. The EIM costs recovered through the 2018 APCU will include operation and maintenance costs and capital costs. The 2018 APCU will include $5.5 million in system EIM benefits, or approximately $255,200 on an Oregon-allocated basis. The $5.5 million in system EIM benefits accounts for $4.5 million in benefits in accordance with a study commissioned by Idaho Power, as well as an additional $1 million in benefits in accordance with Staff's estimate of flexible reserve benefits that were not included in the study. The Oregon-allocated revenue requirement associated with EIM costs to be included in the 2018 APCU is $113,268.

V. DISCUSSION

As noted by the parties in their joint brief, we will adopt a stipulation if it is supported by competent evidence in the record, appropriately resolves the issues in the case, and results in just and reasonable rates.[18]

Both Staff and CUB conducted a thorough investigation of the company's testimony and exhibits, served numerous data requests, and participated in settlement conferences. As a result of its investigation, Staff filed testimony in response to the 2018 October Update, and CUB also filed testimony. The issues raised by Staff and CUB were addressed at settlement meetings and workshops, as well as in the company's responsive testimony. After negotiations, the parties reached agreement on all unresolved issues and have each executed a stipulation. No person has filed an objection to the stipulation. We therefore

[18] Joint Explanatory Brief at 9 (May 1, 2018).

find that the record in the case is sufficient to conclude that the company's calculations as modified by the stipulation are correct and conform to Commission precedent.

We have examined the stipulation, the joint explanatory brief, and the pertinent record in the case. We find that the stipulation is supported by the record, which includes the company's testimony and exhibits describing the detailed calculations supporting both the 2018 October Update and the 2018 March Forecast, Staff testimony thereon, and the stipulated modifications to the March Forecast. We therefore conclude that the resulting rates are just and reasonable for resolution of the issues in this docket. The stipulation should be adopted in its entirety.

VI. ORDER

IT IS ORDERED that:

1. The stipulation between Idaho Power Company, the Staff of the Public Utility Commission of Oregon, and the Oregon Citizens' Utility Board, attached as Appendix A, is adopted.

2. Idaho Power Company must file revised rate schedules consistent with this order to be effective no earlier than June 1, 2018.

Made, entered, and effective MAY 21 2018.

Lisa D. Hardie Chair	**Stephen M. Bloom** Commissioner
PUBLIC UTILITY COMMISSION OF OREGON	**Megan W. Decker** Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 333

In the Matter of

IDAHO POWER COMPANY

2018 ANNUAL POWER COST UPDATE

STIPULATION

This Stipulation resolves all issues among the parties to Idaho Power Company's ("Idaho Power" or "Company") 2018 Annual Power Cost Update ("APCU") filed pursuant to Order No. 08-238.[1] The APCU updates the Company's net power supply expense ("NPSE") and results in new rates, which the mechanism permits to go into effect June 1, 2018.

PARTIES

1. The parties to this Stipulation are Staff of the Public Utility Commission of Oregon ("Staff"), the Oregon Citizens' Utility Board ("CUB"), and Idaho Power (together, the "Stipulating Parties").

BACKGROUND

2. Pursuant to Order No. 08-238, Idaho Power annually updates its NPSE included in rates through an automatic adjustment clause, the APCU. The APCU is comprised of two components—an "October Update" and a "March Forecast." The October Update establishes the prospective base or normalized level of NPSE for an April through March test period. The March Forecast contains the Company's forecast of expected NPSE over the same test period. Pursuant to Order No. 10-191 the Company adjusts base rates to reflect changes in revenue requirement related to the October Update, while the rates resulting from the March Forecast are listed on Schedule 55. The rates associated with the October Update

[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).

and the March Forecast are intended, under the mechanisms, to become effective on June 1 of each year.

3. On October 31, 2017, Idaho Power filed testimony and exhibits for the 2018 October Update component of the APCU ("2018 October Update").[2] Pursuant to Order No. 08-238, Idaho Power reviewed all the inputs and provided changes in the 2018 October Update for the following variables: (1) fuel prices and transportation costs, (2) wheeling expenses, (3) planned outages and forced outage rates, (4) heat rates, (5) forecast of normalized load and normalized sales, (6) contracts for wholesale power and power purchases and sales, (7) forward price curve, (8) Public Utility Regulatory Policies Act of 1978 ("PURPA") expenses, and (9) the Oregon state allocation factor.[3]

4. The test period for the 2018 October Update was April 2018 through March 2019 and included updates to the above-referenced variables for all Company-owned resources and updated sales and load forecasts.[4] The 2018 October Update specifically accounted for changes in coal and natural gas prices, generation and expenses related to contracts entered into pursuant to PURPA, and normalized system load.[5]

5. As part of the fuel expense update, the Company updated its forecast of Oil, Handling, and Administrative and General ("OHAG") expenses per the terms of the 2016 and 2017 APCU settlement stipulations. Per the terms of the 2016 APCU settlement stipulation [6], the per unit OHAG expense included in the AURORA model was updated to reflect the amount of OHAG expense driven by Idaho Power's dispatch of each of its coal plants. The

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[2] *See* Idaho Power/100-109.

[3] Idaho Power/100, Blackwell/4-5.

[4] Idaho Power/100, Blackwell/2 and 5.

[5] Idaho Power/100, Blackwell/5-11.

[6] *Re Idaho Power Company's 2016 Annual Power Cost Update*, Docket No. UE 301, Stipulation at 7 (May 11, 2016).

Company then separately accounted for its proportional share of the total OHAG expense incurred at each of its coal plants. Per the terms of the 2017 APCU settlement stipulation [7] ("2017 Stipulation"), Idaho Power's proportional share of total OHAG expenses incurred at each of its coal plants was forecast using the three-year historical average of actual OHAG costs, with a growth (reduction) rate equal to the five-year historical average growth (reduction) rate. Idaho Power also accounted for revenues received from or expenses paid to NV Energy (its ownership partner in the North Valmy Plant ("Valmy")) for usage of the Company's unused capacity or the Company's usage of NV Energy's unused capacity per the terms of the 2017 Stipulation.

6. The October Update included the Company's estimate of incremental costs and benefits associated with participation in the Western Energy Imbalance Market ("EIM") to be included in the 2018 APCU. The Company proposed to set estimated EIM benefits equal to expected EIM costs. [8]

7. The filed 2018 October Update resulted in a cost per unit of $26.54 per megawatt-hour ("MWh"), representing an increase of 1.8 percent over last year's October Update cost per unit of $26.06 per MWh.[9]

8. For the 2018 October Update, the Company calculated the Oregon jurisdictional share of total NPSE by multiplying the cost per unit of $26.54 per MWh by the forecasted Oregon jurisdictional loss-adjusted normalized sales for the April through March test period, consistent with the methodology approved in the 2017 Stipulation. Idaho Power then calculated the incremental Oregon jurisdictional NPSE by comparing the 2018 October Update Oregon jurisdictional share of total NPSE to the NPSE recovery under current

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[7] *Re Idaho Power Company's 2017 Annual Power Cost Update*, Docket No. UE 314, Stipulation at 7 (April 28, 2017).

[8] Idaho Power/100, Blackwell/14-16.

[9] Idaho Power/100, Blackwell/17.

approved rates from the 2017 APCU October Update, resulting in an incremental revenue requirement of $360,109.[10]

9. The Company's revenue spread methodology for the 2018 October Update allocated the incremental revenue requirement to individual customer classes on the basis of normalized jurisdictional forecasted sales at the generation level for the test period.[11]

10. On November 2, 2017, CUB filed its Notice of Intervention. On January 11, 2018, Administrative Law Judge ("ALJ") Patrick Power held a prehearing conference at which the parties to docket UE 333 agreed upon a procedural schedule that would allow the Public Utility Commission of Oregon ("Commission") to issue an order on Idaho Power's 2018 APCU prior to June 1, 2018.[12]

11. The Stipulating Parties held an initial workshop on January 23, 2018, to discuss the 2018 October Update filing. Staff and CUB served discovery on Idaho Power and conducted a thorough investigation of the 2018 October Update.

12. On February 12, 2018, Staff filed Opening Testimony. Staff's testimony raised concerns related to the following: (1) the method used by the Company to allocate costs between Oregon rate classes; (2) the recovery of depreciation expense for plant owned by Bridger Coal Company ("BCC"); (3) Idaho Power's fueling plan for the Jim Bridger Plant ("Bridger"); (4) Idaho Power's proposal for the recovery of costs—including capital costs—related to its participation in the EIM; and (5) Idaho Power's accounting for the costs related to purchases from qualified facilities (QFs) under PURPA.

13. CUB did not file Opening Testimony.[13]

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[10] Idaho Power/200, Blackwell/18.

[11] Idaho Power/100, Blackwell/20; Idaho Power/108.

[12] *Re Idaho Power Company's 2018 Annual Power Cost Update*, Docket No. UE 333, Prehearing Conference Memorandum at 1 (January 11, 2018).

[13] Letter to Filing Center from William Gehrke, dated February 8, 2018.

14. Idaho Power filed Reply Testimony on March 1, 2018, in which the Company responded to the issues raised in Staff's Opening Testimony.[14] The Company supported its rate spread and allocation proposals, estimates of PURPA costs, and its request to recover EIM costs. In addition, the Company supported its BCC costs, including its method for calculating the depreciable lives of BCC assets.

15. CUB also filed Reply Testimony on March 1, 2018. CUB's testimony focused on a single issue, arguing that the APCU is not the appropriate mechanism by which Idaho Power should recover capital costs related to the EIM.[15]

16. On March 23, 2018, Idaho Power filed the 2018 March Forecast component of the APCU ("2018 March Forecast"). The 2018 March Forecast consisted of direct testimony describing the Company's estimate of the expected NPSE for the upcoming water year—April 2018 through March 2019.[16] Order No. 08-238 calls for the March Forecast to update the following variables: fuel prices, transportation costs, wheeling expenses, planned and forced outages, heat rates, forecast of normalized sales and loads updated for significant changes since the October Update, forecast hydro generation, wholesale power purchase and sale contracts, forward price curve, PURPA expenses, and the Oregon state allocation factor.

17. Idaho Power reviewed all the variables for the March Forecast and the following variables changed since the 2018 October Update: (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 Northwest River Forecast Center ("NRFC") and current reservoir levels, (5) known power purchases

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[14] *See* Idaho Power/200 and 300.

[15] CUB/100, Gehrke/3.

[16] Idaho Power/300-305.

and surplus sales made in compliance with the Company's Energy Risk Management Policy, (6) forward price curve, and (7) PURPA contract expenses.[17]

18. The fuel prices were updated to reflect changes in forecast natural gas and coal costs.[18] The per-unit cost of generation for the Boardman plant decreased 12 percent between the October Updated and March Forecast. The per-unit cost of generation increased at Bridger and Valmy.[19]

19. The Company updated the hydro forecast.[20] For this APCU year, Idaho Power reports that expected inflows and flood control targets are forecast to keep flows generally within power plant capacity through the spring, resulting in a similar generation estimate as compared to last year.[21] Hydro generation in the March Forecast represents a .12 million MWh decrease as compared to the October Update.[22]

20. The filed 2018 March Forecast estimated 331 aMW in PURPA generation, which was 1 aMW lower than projected in the October Update, reflecting a decrease in PURPA expense of 3 percent compared to the October Update.[23]

21. The March Forecast also updated the estimated EIM costs and benefits to be included in the 2018 APCU. On an Oregon allocated basis, the revenue requirement associated with EIM costs is $113,268, which represented an increase of $31,748 over the October Update estimate.[24]

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[17] Idaho Power/400, Blackwell/4.

[18] Idaho Power/400, Blackwell/4-7.

[19] Idaho Power/300, Blackwell/5-6.

[20] Idaho Power/300, Blackwell/8.

[21] Idaho Power/400, Blackwell/9

[22] Idaho Power/300, Blackwell/8-9.

[23] Idaho Power/300, Blackwell/8.

[24] Idaho Power/400, Blackwell/14-15.

22. The Company calculated a March Forecast rate of negative $0.59 per MWh, as compared to last year's March Forecast rate of $ 0.24 per MWh.[25]

23. As filed, the overall proposed revenue impact of the combined October and March rates was a decrease of $0.22 million, or a 0.39 percent decrease overall.[26]

24. The 2018 March Forecast also included the Company's proposed rate spread used to spread the March Forecast revenue requirement to the various customer classes.[27]

25. Staff and CUB conducted a thorough investigation of the March Forecast.

26. Settlement conferences were held on February 20, 2018, and April 3, 2018. Ultimately the Stipulating Parties resolved all the issues in this case through these discussions, resulting in the settlement stipulation as described in this Agreement.

AGREEMENT

27. The Stipulating Parties agree that Idaho Power will adopt a modified rate spread methodology. Under the proposed modified methodology, the Oregon jurisdictional share of total NPSE, instead of the Oregon jurisdictional share of incremental NPSE, will be allocated to individual customer classes on the basis of normalized jurisdictional forecasted sales at the generation level for the forecast April through March test period. Any rate increases resulting from application of this methodology as applied to a customer class will be limited to three percent above the overall average rate increase on a percentage of total revenue basis. For example, if the overall revenue impact of the APCU is an increase in total billed revenue of 0.5 percent, rate increases for each customer class will be limited to 3.5 percent.

28. The Stipulating Parties agree that no later than July 31, 2018, Idaho Power will provide to the Stipulating Parties analysis of the long-term fueling plan for Bridger based on

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[25] Idaho Power/300, Blackwell/16.

[26] Idaho Power/400, Blackwell/18.

[27] Idaho Power/300, Blackwell/15-16; Idaho Power/304.

information known at the time of its creation. As part of that analysis, Idaho Power will compare the costs of Option A with Option B.

29. The Stipulating Parties agree that in future APCU filings, Idaho Power will include information setting forth how and why BCC depreciation expense has changed from the levels set in the Company's most recent general rate case. The Stipulating Parties agree that Idaho Power will provide workpapers in future APCU filings to support the depreciable lives of Bridger Coal Company assets. The Stipulating Parties will continue to work together to determine the types of workpapers to be included with future APCU filings prior to the filing of the 2019 APCU in October 2018.

30. The Stipulating Parties agree that Idaho Power will implement adjustments to the PURPA forecast included in the March Forecast of the APCU, beginning with the 2018 APCU March Forecast. First, for any new PURPA project expected to come online during the APCU forecast test period, the forecast generation and expense will be included in the forecast beginning in the month in which the project is expected to come online. For example, if a new PURPA project is expected to come online in December of the APCU forecast test period, the forecast generation and expense for the project will be included in the PURPA forecast beginning in December. Second, the expected online date for any new PURPA project will be adjusted using the three-year average Contract Delay Rate ("CDR") of historical PURPA projects. The CDR is based on the average of differences in scheduled operation date and actual operation date for historical PURPA projects. The three-year historical average CDR will be applied to any new PURPA project expected to come online during the forecast test period for the March Forecast of the APCU. The methodology used to calculate the CDR for the 2018 APCU is provided as Exhibit 1 to this stipulation.

31. The Stipulating Parties agree that the EIM costs recovered through the 2018 APCU will include operation and maintenance costs and capital costs. The 2018 APCU will include $5.5 million in system EIM benefits, or approximately $255,200 on an Oregon-

allocated basis. The $5.5 million in system EIM benefits accounts for $4.5 million in estimated benefits as determined by the Energy + Environmental Economics, Inc. ("E3") EIM study commissioned by Idaho Power, as well as an additional $1 million in benefits in accordance with Staff's estimate of flexible reserve benefits that were not included in the E3 study.[28] The Oregon-allocated revenue requirement associated with EIM costs to be included in the 2018 APCU is $113,268. The parties emphasize that the agreement to include these costs and benefits in the APCU is the result of a compromise of positions and should not be viewed as reflecting any party's agreement to this approach in other circumstances.

32. Based on the foregoing agreements, the Stipulating Parties agree to Idaho Power's requested revenue requirement decrease of $376,324, or a 0.68 percent decrease in current billed revenue.

33. The Stipulating Parties agree that rates agreed to by the terms of this Stipulation should be made effective on June 1, 2018, as permitted by the APCU mechanism.

34. The Stipulating Parties agree the result is in conformance with the methodology adopted by the Commission in Order No. 08-238 and Order No. 17-165.

35. The Stipulating Parties agree that the rate decrease resulting from the Stipulation results in rates that are fair, just, and reasonable.

36. The Stipulating Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented.

37. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-001-0350(7). The Stipulating Parties agree to support this Stipulation throughout this proceeding and any appeal, (if necessary) provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein.

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[28] Staff/400, Gibbens/4.

38. If this Stipulation is challenged, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation. The Stipulating Parties agree to cooperate in cross-examination and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Stipulation.

39. The Stipulating Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right, pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation or to withdraw from the Stipulation. Stipulating Parties shall be entitled to seek rehearing or reconsideration pursuant to OAR 860-001-0720 in any manner that is consistent with the agreement embodied in this Stipulation.

40. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation, other than those specifically identified in the body of this Stipulation. No Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Stipulation.

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41. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

42. This Stipulation is entered into by each Stipulating Party on the date entered below such Stipulating Party's signature.

STAFF

By: for Stephanie Andrus

Date: 5/1/18

IDAHO POWER

By: ______________________________

Date: ______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date: ______________________________

41. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

42. This Stipulation is entered into by each Stipulating Party on the date entered below such Stipulating Party's signature.

STAFF

By: ______________________

Date: ______________________

IDAHO POWER

By: Lisa Rackner

Date: 5-1-18

OREGON CITIZENS' UTILITY BOARD

By: ______________________

Date: ______________________

41. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

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STAFF

By: ______________________________

Date:______________________________

IDAHO POWER

By: ______________________________

Date:______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date: 4/27/18

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 333

STIPULATION

Exhibit 1
Revised October Update NPSE with EIM Benefits

May 1, 2018

ORDER NO. 18 170

IPCO POWER SUPPLY EXPENSES FOR APRIL 1, 2018 -- MARCH 31, 2019 (Multiple Gas Prices/89 Hydro Year Conditions)
Repriced Using UE 195 Settlement Methodology - 2018 October Update
AVERAGE

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	885,182.1	952,651.2	917,349.3	699,905.3	480,006.8	561,102.5	543,922.8	458,232.2	676,610.9	758,719.4	838,774.5	857,895.4	8,630,352.4
	Bridger													
2	Energy (MWh)	12,053.1	8,007.8	58,468.1	226,618.4	275,862.2	97,600.0	72,872.7	104,608.2	156,285.1	133,551.2	87,253.5	67,353.4	1,300,533.7
3	Expense ($ x 1000)	$ 683.3	$ 537.3	$ 2,341.7	$ 8,219.7	$ 9,919.0	$ 3,705.9	$ 2,887.3	$ 4,007.7	$ 5,831.3	$ 4,838.4	$ 3,259.7	$ 2,591.1	$ 48,822.4
	Boardman													
4	Energy (MWh)	7,362.4	6,723.3	14,975.3	33,087.6	38,238.4	25,855.3	21,148.3	26,635.3	28,786.9	22,763.7	13,510.9	12,211.5	251,299.0
5	Expense ($ x 1000)	$ 235.0	$ 218.0	$ 449.4	$ 957.2	$ 1,102.2	$ 756.2	$ 626.2	$ 777.4	$ 838.0	$ 710.0	$ 433.7	$ 396.1	$ 7,499.4
	Valmy													
6	Energy (MWh)	9,263.2	7,727.8	26,565.7	83,948.0	112,300.7	46,892.0	34,255.6	49,123.1	59,293.1	47,908.1	27,832.6	24,799.5	529,909.3
7	Expense ($ x 1000)	$ 678.9	$ 627.0	$ 1,228.2	$ 3,011.2	$ 3,891.4	$ 1,871.3	$ 1,480.9	$ 1,940.6	$ 2,256.3	$ 1,894.7	$ 1,263.6	$ 1,153.5	$ 21,297.8
	Langley Gulch													
8	Energy (MWh)	178,162.3	186,452.0	185,677.3	198,549.6	199,045.6	194,474.6	197,157.3	193,209.2	198,311.3	198,599.1	168,657.1	177,491.9	2,275,787.3
9	Expense ($ x 1000)	$ 2,866.7	$ 2,933.5	$ 2,940.6	$ 3,628.9	$ 3,635.1	$ 3,492.9	$ 3,515.3	$ 4,165.7	$ 4,867.8	$ 4,703.6	$ 3,661.3	$ 3,701.7	$ 44,113.1
	Danskin													
10	Energy (MWh)	7,591.1	10,381.6	53,286.2	94,524.7	118,678.9	68,562.9	50,471.0	23,086.6	8,791.9	4,425.6	5,886.5	2,251.0	447,938.1
11	Expense ($ x 1000)	$ 191.1	$ 270.7	$ 1,453.9	$ 2,825.4	$ 3,533.5	$ 1,932.7	$ 1,390.7	$ 675.0	$ 295.9	$ 165.0	$ 213.2	$ 78.8	$ 13,025.9
	Bennett Mountain													
12	Energy (MWh)	2,840.9	3,050.1	31,950.7	61,247.8	79,612.5	42,357.0	29,833.2	10,180.9	4,577.0	1,530.8	3,362.1	773.0	271,316.1
13	Expense ($ x 1000)	$ 72.6	$ 79.5	$ 881.1	$ 1,804.0	$ 2,308.5	$ 1,186.3	$ 815.1	$ 288.7	$ 158.0	$ 61.7	$ 127.5	$ 27.3	$ 7,810.3
14	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 695.1	$ 717.9	$ 716.1	$ 739.6	$ 739.6	$ 716.1	$ 713.4	$ 690.8	$ 713.4	$ 712.0	$ 644.1	$ 712.0	$ 8,509.8
	Purchased Power (Excluding CSPP)													
15	Market Energy (MWh)	9,041.2	9,683.3	57,344.2	60,814.4	72,455.9	28,774.1	17,519.2	73,868.3	45,079.3	76,370.9	11,516.0	12,935.2	475,402.0
16	Elkhorn Wind Energy (MWh)	26,520.8	25,525.8	24,790.8	26,601.0	23,943.0	21,200.4	22,027.8	30,132.4	29,442.4	24,406.6	24,037.6	26,788.0	305,416.3
17	Neal Hot Springs Energy (MWh)	14,315.7	11,493.2	10,545.1	8,775.0	9,512.8	11,769.1	12,824.2	16,268.0	18,722.7	17,961.6	16,403.0	16,710.6	165,300.9
18	Raft River Geothermal Energy (MWh)	6,436.3	5,156.4	5,315.6	5,768.1	5,254.4	5,967.1	6,353.2	6,873.5	7,236.1	7,122.3	6,304.8	6,671.6	74,459.3
19	Total Energy Excl. CSPP (MWh)	56,313.9	51,858.7	97,995.6	101,958.4	111,166.1	67,710.7	58,724.4	127,142.1	100,480.4	125,861.4	58,261.4	63,105.4	1,020,578.5
20	Market Expense ($ x 1000)	$ 166.2	$ 158.7	$ 899.1	$ 1,431.1	$ 2,045.6	$ 742.0	$ 417.6	$ 1,955.6	$ 1,350.5	$ 2,333.9	$ 323.2	$ 318.2	$ 12,141.6
21	Elkhorn Wind Expense ($ x 1000)	$ 1,217.0	$ 1,171.4	$ 1,547.7	$ 1,992.7	$ 1,793.6	$ 1,323.5	$ 1,375.2	$ 2,257.2	$ 2,205.5	$ 1,569.3	$ 1,545.6	$ 1,266.0	$ 19,264.8
22	Neal Hot Springs Expense ($ x 1000)	$ 1,201.4	$ 964.5	$ 1,207.3	$ 1,205.5	$ 1,306.9	$ 1,347.4	$ 1,468.2	$ 2,234.9	$ 2,572.1	$ 2,091.6	$ 1,910.1	$ 1,426.4	$ 18,936.4
23	Raft River Geothermal Expense ($ x 1000)	$ 312.2	$ 250.1	$ 350.8	$ 456.8	$ 416.1	$ 393.8	$ 419.2	$ 544.3	$ 573.0	$ 479.9	$ 424.8	$ 330.4	$ 4,951.3
24	Total Expense Excl. CSPP ($ x 1000)	$ 2,896.7	$ 2,544.7	$ 4,004.9	$ 5,086.0	$ 5,562.2	$ 3,806.7	$ 3,680.2	$ 6,992.0	$ 6,701.2	$ 6,474.7	$ 4,203.7	$ 3,341.0	$ 55,294.2
	Surplus Sales													
25	Energy (MWh)	315,245.4	247,863.7	103,441.7	23,787.7	13,429.6	56,525.8	79,933.8	8,054.7	50,036.9	54,847.1	196,075.1	242,923.9	1,392,165.4
26	Revenue Including Transmission Costs ($ x 1000)	$ 5,253.5	$ 3,682.7	$ 1,470.0	$ 507.4	$ 343.8	$ 1,321.6	$ 1,727.9	$ 193.4	$ 1,359.5	$ 1,520.1	$ 4,990.4	$ 5,420.2	$ 27,790.5
27	Transmission Costs ($ x 1000)	$ 315.2	$ 247.9	$ 103.4	$ 23.8	$ 13.4	$ 56.5	$ 79.9	$ 8.1	$ 50.0	$ 54.8	$ 196.1	$ 242.9	$ 1,392.2
28	Revenue Excluding Transmission Costs ($ x 1000)	$ 4,938.3	$ 3,434.8	$ 1,366.6	$ 483.6	$ 330.3	$ 1,265.1	$ 1,647.9	$ 185.3	$ 1,309.5	$ 1,465.3	$ 4,794.3	$ 5,177.3	$ 26,398.3
29	Net Power Supply Expenses ($ x 1000)	$ 3,381.2	$ 4,493.8	$ 12,649.3	$ 25,788.3	$ 30,361.2	$ 16,203.1	$ 13,461.3	$ 19,352.6	$ 20,352.3	$ 18,094.9	$ 9,012.5	$ 6,824.2	$ 179,974.7
30	PURPA ($ x 1000)	$ 17,582.1	$ 19,584.5	$ 21,761.0	$ 25,654.1	$ 23,655.6	$ 18,171.9	$ 15,587.7	$ 17,898.9	$ 17,887.8	$ 11,853.5	$ 14,314.1	$ 13,255.9	$ 217,207.2
31	EIM Benefits													$ 5,500.0
32	Total Net Power Supply Expenses ($ x 1000)	$ 20,963.3	$ 24,078.3	$ 34,410.3	$ 51,442.4	$ 54,016.9	$ 34,375.0	$ 29,049.0	$ 37,251.6	$ 38,240.1	$ 29,948.4	$ 23,326.7	$ 20,080.1	$ 391,681.9
33	Sales at Customer Level (In 000s MWH)	1,046.856	1,088.531	1,253.529	1,518.425	1,587.884	1,443.479	1,134.623	1,056.620	1,182.173	1,295.156	1,231.836	1,123.754	14,962.866
34	Hours in Month	720	744	720	744	744	720	744	721	744	744	672	743	8760
35	Unit Cost / MWH (for PCAM)	$20.03	$22.12	$27.45	$33.88	$34.02	$23.81	$25.60	$35.26	$32.35	$23.12	$18.94	$17.87	$26.18
	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	$20.00	$19.24	$19.28	$28.18	$32.04	$28.49	$24.54	$27.19	$31.15	$31.37	$28.49	$24.96	
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	$18.56	$17.85	$17.89	$26.15	$29.73	$26.43	$22.77	$25.23	$28.90	$29.11	$26.43	$23.16	
	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	$15.46	$11.27	$9.20	$15.17	$21.39	$20.92	$22.56	$25.18	$27.82	$29.10	$27.30	$23.95	
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	$13.49	$9.83	$8.02	$13.23	$18.65	$18.25	$19.68	$21.96	$24.26	$25.38	$23.81	$20.89	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 333

STIPULATION

Exhibit 2
Revised March Forecast NPSE with EIM Benefits

May 1, 2018

Settlement Stipulation
Exhibit No. 2

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

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	1,150,817.5	1,080,698.5	959,452.5	663,106.1	538,915.8	363,058.2	473,489.4	394,576.0	585,260.4	687,487.2	733,315.3	881,348.2	8,511,525.1
	Bridger													
2	Energy (MWh)	-	-	118.0	159,129.6	208,926.1	121,886.6	36,534.0	109,262.6	133,883.4	67,267.2	33,342.9	-	870,350.5
3	AURORA Modeled Expense ($ x 1000)	$ -	$ -	$ 4.3	$ 5,661.9	$ 7,436.7	$ 4,390.3	$ 1,373.7	$ 4,106.0	$ 4,853.9	$ 2,454.9	$ 1,236.5	$ -	$ 31,518.1
4	AURORA Modeled Handling Expense ($ x 1000)	$ -	$ -	$ 0.0	$ 25.5	$ 33.4	$ 19.5	$ 5.8	$ 17.5	$ 21.4	$ 10.8	$ 5.3	$ -	$ 139.3
5	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ -	$ -	$ 4.3	$ 5,636.4	$ 7,403.3	$ 4,370.8	$ 1,367.9	$ 4,088.5	$ 4,832.5	$ 2,444.1	$ 1,231.1	$ -	$ 31,378.8
6	IPC Share of OHAG Expense ($ x 1000)	$ 209.9	$ 209.9	$ 209.9	$ 209.9	$ 209.9	$ 209.9	$ 209.9	$ 209.9	$ 209.9	$ 209.9	$ 209.9	$ 209.9	$ 2,518.9
7	Total Expense ($ x 1000)	$ 209.9	$ 209.9	$ 214.2	$ 5,846.3	$ 7,613.2	$ 4,580.7	$ 1,577.8	$ 4,298.4	$ 5,042.4	$ 2,654.0	$ 1,441.1	$ 209.9	$ 33,897.8
	Boardman													
8	Energy (MWh)	4,213.8	1,301.2	15,163.3	38,848.9	40,177.4	34,548.2	26,667.7	29,384.7	34,366.5	31,692.1	22,329.1	10,975.1	289,667.9
9	AURORA Modeled Expense ($ x 1000)	$ 123.0	$ 39.5	$ 390.8	$ 977.2	$ 1,010.5	$ 870.2	$ 675.8	$ 742.6	$ 864.9	$ 834.6	$ 595.3	$ 307.3	$ 7,431.6
10	AURORA Modeled Handling Expense ($ x 1000)	$ 0.2	$ 0.1	$ 0.8	$ 1.9	$ 2.0	$ 1.7	$ 1.3	$ 1.5	$ 1.7	$ 1.6	$ 1.1	$ 0.5	$ 14.5
11	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 122.8	$ 39.5	$ 390.0	$ 975.2	$ 1,008.5	$ 868.5	$ 674.5	$ 741.1	$ 863.2	$ 833.1	$ 594.2	$ 306.7	$ 7,417.1
12	IPC Share of OHAG Expense ($ x 1000)	$ 17.7	$ 17.7	$ 17.7	$ 17.7	$ 17.7	$ 17.7	$ 17.7	$ 17.7	$ 17.7	$ 17.7	$ 17.7	$ 17.7	$ 212.8
13	Total Expense ($ x 1000)	$ 140.5	$ 57.2	$ 407.7	$ 993.0	$ 1,026.2	$ 886.2	$ 692.2	$ 758.8	$ 880.9	$ 850.8	$ 611.9	$ 324.5	$ 7,629.9
	Valmy													
14	Energy (MWh)	-	-	1,215.8	65,204.3	67,346.1	57,060.3	29,184.7	41,536.7	72,175.2	47,720.9	23,607.3	79.9	405,131.2
15	AURORA Modeled Expense ($ x 1000)	$ -	$ -	$ 39.3	$ 2,155.4	$ 2,204.2	$ 1,901.1	$ 1,024.2	$ 1,383.2	$ 2,350.4	$ 1,594.1	$ 823.2	$ 2.9	$ 13,478.2
16	AURORA Modeled Handling Expense ($ x 1000)	$ -	$ -	$ 1.1	$ 60.0	$ 62.0	$ 52.5	$ 26.8	$ 38.2	$ 66.4	$ 43.9	$ 21.7	$ 0.1	$ 372.7
17	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ -	$ -	$ 38.2	$ 2,095.4	$ 2,142.3	$ 1,848.6	$ 997.4	$ 1,345.0	$ 2,284.0	$ 1,550.2	$ 801.5	$ 2.8	$ 13,105.4
18	IPC Share of OHAG Expense ($ x 1000)	$ 326.9	$ 326.9	$ 326.9	$ 326.9	$ 326.9	$ 326.9	$ 326.9	$ 326.9	$ 326.9	$ 326.9	$ 326.9	$ 326.9	$ 3,923.3
19	Usage Charges Paid to IPC ($ x 1000)													$ 48.4
20	Total Expense ($ x 1000)	$ 326.9	$ 326.9	$ 365.1	$ 2,422.4	$ 2,469.2	$ 2,175.5	$ 1,324.3	$ 1,672.0	$ 2,611.0	$ 1,877.2	$ 1,128.4	$ 329.8	$ 16,980.4
	Langley Gulch													
21	Energy (MWh)	179,776.6	198,754.0	190,861.9	199,049.8	199,049.8	194,647.7	197,343.3	193,112.3	211,799.1	211,628.5	180,200.5	189,876.9	2,346,100.4
22	Expense ($ x 1000)	$ 2,659.0	$ 2,914.6	$ 2,913.6	$ 2,963.2	$ 3,106.0	$ 3,277.7	$ 3,210.5	$ 3,694.6	$ 4,744.3	$ 4,377.3	$ 3,529.6	$ 3,308.6	$ 40,699.0
	Danskin													
23	Energy (MWh)	324.5	317.3	40,418.1	158,021.3	162,922.3	109,665.2	83,461.7	47,663.1	7,203.5	7,080.2	5,230.4	5,086.7	627,394.2
24	Expense ($ x 1000)	$ 8.0	$ 7.8	$ 1,035.9	$ 4,128.7	$ 4,462.3	$ 3,115.5	$ 2,268.4	$ 1,496.2	$ 262.1	$ 238.8	$ 167.8	$ 146.1	$ 17,337.6
	Bennett Mountain													
25	Energy (MWh)	-	-	16,761.8	106,264.2	109,564.6	80,361.1	45,889.6	23,379.1	3,192.9	851.5	2,767.9	2,021.0	391,053.7
26	Expense ($ x 1000)	$ -	$ -	$ 433.9	$ 2,691.1	$ 2,898.9	$ 2,277.8	$ 1,258.1	$ 743.9	$ 117.9	$ 29.2	$ 90.2	$ 59.0	$ 10,599.9
27	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 696.5	$ 719.3	$ 723.5	$ 747.2	$ 747.2	$ 723.5	$ 714.8	$ 692.2	$ 714.8	$ 713.5	$ 645.6	$ 713.5	$ 8,551.4
	Purchased Power (Excluding PURPA)													
28	Market Energy (MWh)	-	-	56,854.3	40,970.0	50,724.8	62,143.8	18,512.5	98,559.2	104,699.6	135,733.3	36,445.9	6,665.8	611,309.1
29	Elkhorn Wind Energy (MWh)	26,520.8	25,525.8	25,150.8	26,303.4	23,209.4	21,015.4	23,409.4	30,182.4	27,577.6	24,216.8	24,037.6	26,788.0	303,937.1
30	Neal Hot Springs Energy (MWh)	14,315.7	11,493.2	10,545.1	8,775.0	9,512.8	11,769.1	12,824.2	16,268.0	18,722.7	17,961.6	16,403.0	16,710.6	165,300.9
31	Raft River Geothermal Energy (MWh)	6,436.3	5,156.4	5,315.6	5,768.1	5,254.4	5,967.1	6,353.2	6,873.5	7,236.1	7,122.3	6,304.8	6,671.6	74,459.3
32	Total Energy Excl. PURPA (MWh)	47,272.8	42,175.4	97,865.8	81,816.5	88,701.4	100,895.4	61,099.2	151,883.0	158,235.9	185,034.0	83,191.3	56,836.0	1,155,006.5
33	Market Expense ($ x 1000)	$ -	$ -	$ 456.7	$ 875.6	$ 1,349.9	$ 1,649.9	$ 430.8	$ 2,122.0	$ 2,900.6	$ 3,428.1	$ 804.9	$ 114.1	$ 14,132.5
34	Elkhorn Wind Expense ($ x 1000)	$ 1,217.0	$ 1,171.4	$ 1,570.2	$ 1,970.4	$ 1,738.6	$ 1,312.0	$ 1,461.4	$ 2,261.0	$ 2,065.8	$ 1,557.1	$ 1,545.6	$ 1,266.0	$ 19,136.6
35	Neal Hot Springs Expense ($ x 1000)	$ 1,201.4	$ 964.5	$ 1,207.3	$ 1,205.5	$ 1,306.9	$ 1,347.4	$ 1,468.2	$ 2,234.9	$ 2,572.1	$ 2,091.6	$ 1,910.1	$ 1,426.4	$ 18,936.4
36	Raft River Geothermal Expense ($ x 1000)	$ 312.2	$ 250.1	$ 350.8	$ 456.8	$ 416.1	$ 393.8	$ 419.2	$ 544.3	$ 573.0	$ 479.9	$ 424.8	$ 330.4	$ 4,951.3
37	Total Expense Excl. PURPA ($ x 1000)	$ 2,730.6	$ 2,386.0	$ 3,585.0	$ 4,508.3	$ 4,811.5	$ 4,703.1	$ 3,779.7	$ 7,162.1	$ 8,111.6	$ 7,556.8	$ 4,685.5	$ 3,136.9	$ 57,156.8
	Surplus Sales													
38	Energy (MWh)	533,073.1	345,919.7	41,057.5	18,325.9	19,135.5	9,619.7	38,114.7	4,427.2	11,686.8	9,788.1	68,079.9	179,731.9	1,278,960.0
39	Revenue Including Transmission Expenses ($ x 1000)	$ 7,259.0	$ 3,081.5	$ 419.6	$ 375.5	$ 607.2	$ 240.2	$ 796.1	$ 83.0	$ 313.3	$ 239.2	$ 1,481.3	$ 3,154.4	$ 18,050.4
40	Transmission Expenses ($ x 1000)	$ 533.1	$ 345.9	$ 41.1	$ 18.3	$ 19.1	$ 9.6	$ 38.1	$ 4.4	$ 11.7	$ 9.8	$ 68.1	$ 179.7	$ 1,279.0
41	Revenue Excluding Transmission Expenses ($ x 1000)	$ 6,725.9	$ 2,735.6	$ 378.5	$ 357.2	$ 588.0	$ 230.6	$ 758.0	$ 78.6	$ 301.6	$ 229.5	$ 1,413.2	$ 2,974.6	$ 16,771.4
	Net Hedges													
42	Energy (MWh)	-	-	-	21,104.0	12,960.0	-	-	-	-	-	-	-	34,064.0
43	Cost($ X 1000)	$ -	$ -	$ -	$ 432.9	$ 372.6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 805.5
44	Net Power Supply Expenses ($ x 1000)	$ 45.6	$ 3,886.1	$ 9,300.4	$ 24,375.7	$ 26,918.9	$ 21,509.4	$ 14,067.9	$ 20,439.6	$ 22,183.3	$ 18,068.1	$ 10,886.8	$ 5,253.5	$ 176,887.0
45	PURPA ($ x 1000)	$ 17,297.4	$ 19,512.8	$ 21,753.9	$ 24,206.4	$ 22,314.0	$ 18,075.7	$ 16,499.6	$ 16,135.7	$ 15,245.1	$ 12,558.6	$ 13,866.6	$ 13,102.3	$ 210,568.1
46	EIM Benefits													$ 5,500.0
47	Total Net Power Supply Expenses ($ x 1000)	$ 17,342.9	$ 23,398.8	$ 31,054.3	$ 48,582.2	$ 49,233.0	$ 39,585.1	$ 30,567.5	$ 36,575.3	$ 37,428.4	$ 30,626.7	$ 24,753.4	$ 18,355.8	$ 381,955.0
48	Sales at Customer Level (In 000s MWH)	1,046.856	1,088.531	1,253.529	1,518.425	1,587.884	1,443.479	1,134.623	1,056.620	1,182.173	1,295.156	1,231.836	1,123.754	14,962.866
49	Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
50	Unit Cost / MWH (for PCAM)	$16.57	$21.50	$24.77	$32.00	$31.01	$27.42	$26.94	$34.62	$31.66	$23.65	$20.09	$16.33	**$25.53**
	Prices Used in Purchased Power & Surplus Sales Above:													
	Heavy Load													
51	Portion of Purchased Power considered HL Purchases	0.00%	0.00%	42.70%	48.20%	20.50%	51.59%	53.98%	55.27%	44.15%	37.27%	19.64%	3.04%	
52	Purchased Power HL Price	16.62	12.94	14.29	28.05	35.33	29.35	24.57	22.70	30.23	28.47	24.36	19.74	
53	Portion of Surplus Sales considered HL Surplus Sales	64.27%	62.78%	70.56%	56.79%	90.93%	66.20%	50.20%	34.90%	77.88%	67.44%	77.89%	77.91%	
54	Surplus Sales HL Price	15.42	12.00	13.26	26.03	32.78	27.23	22.80	21.06	28.05	26.41	22.61	18.32	
	Light Load													
55	Portion of Purchased Power considered LL Purchases	0.00%	0.00%	57.30%	51.80%	79.50%	48.41%	46.02%	44.73%	55.85%	62.73%	80.36%	96.96%	
56	Purchased Power LL Price	11.89	4.23	3.37	15.15	24.37	23.56	21.74	20.08	25.70	23.35	21.53	17.03	
57	Portion of Surplus Sales considered LL Surplus Sales	35.73%	37.22%	29.44%	43.21%	9.07%	33.80%	49.80%	65.10%	22.12%	32.56%	22.11%	22.09%	
58	Surplus Sales LL Price	10.37	3.69	2.94	13.22	21.25	20.55	18.96	17.51	22.42	20.36	18.77	14.85	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 333

STIPULATION

Exhibit 3
Revised Combined Rate Calculation

May 1, 2018

APCU Combined Rate Calculation
April 2018 - March 2019

Line	OCTOBER APCU	
1	Forecast of Normalized Sales (MWh)	14,962,866
2	Total Net Power Supply Expense	$391,681,877
3	October APCU Unit Cost ($/MWh)	$26.18
	MARCH FORECAST	
4	Forecast of Normalized Sales (MWh)	14,962,866
5	Total Net Power Supply Expense	$381,955,040
6	March Forecast Unit Cost ($/MWh)	$25.53
7	Sales Adjusted Forecast Power Cost Change	-$9,725,863
8	Portion of Change Allowed	95%
9	Forecast Change Allowed	($9,239,570)
10	**March Forecast Rate ($/MWh)**	($0.62)
11	**Combined Rate ($/MWh)**	$25.56

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 333

STIPULATION

Exhibit 4
Revised Revenue Spread – Revenue Impact – Total NPSE Methodology

May 1, 2018

Idaho Power Company
Revenue Spread Exhibit for 2018 APCU October Update
Stipulated Revenue Spread

Line No.		
1	2018 October Update Oregon Jurisdictional Share of Base NPSE = $26.18/MWh x 694,276.451 MWhs =	$18,176,157
2	Oregon Allocated EIM Costs	$113,268
3	Proposed October Update APCU Revenue Requirement	$18,289,425

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 2018 - March 2019 Generation Level Normalized Sales (kWh)**	**748,251,156**	209,227,304	20,744,179	130,134,511	17,351,238	3,138,528	475,798	183,804,202	110,241,240	72,113,759	5,904	989,628	24,865
5	**Class Share of April 2018 - March 2019 Generation Level Normalized Sales (kWh)**	**100%**	27.96%	2.77%	17.39%	2.32%	0.42%	0.06%	24.56%	14.73%	9.64%	0.00%	0.13%	0.00%
6	**2018 October Update Class Allocated Base NPSE**	$ 18,289,425	$ 5,114,121	$ 507,048	$ 3,180,864	$ 424,115	$ 76,715	$ 11,630	$ 4,492,707	$ 2,694,615	$ 1,762,669	$ 144	$ 24,189	$ 608
7	**June 2018 - May 2019 Loss-Adjusted Normalized Sales (kWh)**	**695,839,775**	191,153,085	18,933,523	118,780,814	16,359,226	3,035,328	434,123	173,550,380	106,832,451	65,829,824	5,388	902,945	22,688
8	**Proposed APCU Rates for 2018 October Update ($/kWh)**	**0.02628**	**0.02675**	**0.02678**	**0.02678**	**0.02593**	**0.02527**	**0.02679**	**0.02589**	**0.02522**	**0.02678**	**0.02678**	**0.02679**	**0.02679**
9	**Proposed October Update APCU Revenue Requirement**	**$18,289,425**	$5,114,121	$507,048	$3,180,864	$424,115	$76,715	$11,630	$4,492,707	$2,694,615	$1,762,669	$144	$24,189	$608

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	**APCU Rates for 2017 October Update - Order No. 17-165**	**25.979**	31.101	25.408	25.878	23.452	26.369	22.645	24.906	19.884	24.793	60.766	17.563	18.916
11	**June 2018 - May 2019 Loss-Adjusted Normalized Sales (kWh)**	**695,839,775**	191,153,085	18,933,523	118,780,814	16,359,226	3,035,328	434,123	173,550,380	106,832,451	65,829,824	5,388	902,945	22,688
12	**Base NPSE Recovered under Current APCU Rates**	**$18,068,893**	$5,944,979	$481,057	$3,073,866	$383,657	$80,040	$9,831	$4,322,474	$2,124,262	$1,632,112	$327	$15,859	$429

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
APCU October Update
Effective June 1, 2018

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	Adjustments to Base Revenue	Percent Change Base to Base Revenue	Stipulated Revenue Increase 3.4% Cap	Revenue Requirement Shortfall
	Uniform Tariff Rates:												
1	Residential Service	1	13,720	191,153,085	$13,256,174	$5,944,979	$19,201,153	$5,114,121	$18,370,295	($830,857)	(4.33)%	-$830,857	$0
2	Small General Service	7	2,540	18,933,523	$1,508,938	$481,057	$1,989,995	$507,048	$2,015,986	$25,991	1.31%	$25,991	$0
3	Large General Secondary	9S	943	118,780,814	$6,239,807	$3,073,866	$9,313,673	$3,180,864	$9,420,671	$106,998	1.15%	$106,998	$0
4	Large General Primary	9P	6	16,359,226	$746,600	$383,657	$1,130,257	$424,115	$1,170,715	$40,458	3.58%	$38,429	$2,029
5	Large General Transmission	9T	1	3,035,328	$124,517	$80,040	$204,557	$76,715	$201,232	($3,325)	(1.63)%	-$3,325	$0
6	Dusk to Dawn Lighting	15	0	434,123	$98,510	$9,831	$108,341	$11,630	$110,140	$1,799	1.66%	$1,799	$0
8	Large Power Primary	19P	6	173,550,380	$6,406,873	$4,322,474	$10,729,347	$4,492,707	$10,899,580	$170,233	1.59%	$170,233	$0
9	Large Power Transmission	19T	1	106,832,451	$4,020,341	$2,124,262	$6,144,603	$2,694,615	$6,714,957	$570,353	9.28%	$208,917	$361,437
10	Agricultural Irrigation Service	24	1,988	65,829,824	$4,795,387	$1,632,112	$6,427,499	$1,762,669	$6,558,056	$130,557	2.03%	$130,557	$0
11	Unmetered General Service	40	2	5,388	$217	$327	$544	$144	$361	($183)	(33.65)%	-$183	$0
12	Street Lighting	41	10	902,945	$126,775	$15,859	$142,634	$24,189	$150,964	$8,331	5.84%	$4,850	$3,481
13	Traffic Control Lighting	42	8	22,688	$1,703	$429	$2,132	$608	$2,310	$179	8.38%	$72	$106
14	Total Uniform Tariffs		19,225	695,839,775	$37,325,843	$18,068,893	$55,394,735	$18,289,425	$55,615,268	$220,533	0.40%		$367,053
15	Total Oregon Retail Sales		19,225	695,839,775	$37,325,843	$18,068,893	$55,394,735	$18,289,425	$55,615,268	$220,533	0.40%		

(1) Updated June 2018-May 2019 Test Year

Idaho Power Company
Revenue Spread Exhibit for 2018 APCU October Update
Stipulated Revenue Spread

Line No.		
1	3.4% Increase Cap - Revenue Requirement Shortfall	$367,053

Line No.		TOTAL SYSTEM	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV SECONDARY (9-S)	GEN SRV PRIMARY (9-P)	GEN SRV TRANS (9-T)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	LG POWER TRANS (19-T)	IRRIGATION SECONDARY (24-S)	UNMETERED GEN SERVICE (40)	MUNICIPAL ST LIGHT (41)	TRAFFIC CONTROL (42)
7	**April 2018 - March 2019 Generation Level Normalized Sales (kWh)**	**619,644,185**	209,227,304	20,744,179	130,134,511		3,138,528	475,798	183,804,202		72,113,759	5,904		
8	**Class Share of April 2018 - March 2019 Generation Level Normalized Sales (kWh)**	**100%**	33.77%	3.35%	21.00%		0.51%	0.08%	29.66%		11.64%	0.00%		
9	**2018 October Update Class Allocated Base NPSE**	$ 367,053	$ 123,938	$ 12,288	$ 77,087		$ 1,859	$ 282	$ 108,879		$ 42,717	$ 3		
10	**June 2018 - May 2019 Loss-Adjusted Normalized Sales (kWh)**	**571,722,465**	191,153,085	18,933,523	118,780,814		3,035,328	434,123	173,550,380		65,829,824	5,388		
11	**Proposed APCU Rates for 2018 October Update ($/kWh)**	**0.00064**	**0.00065**	**0.00065**	**0.00065**		**0.00061**	**0.00065**	**0.00063**		**0.00065**	**0.00065**		
12	**Proposed October Update APCU Revenue Requirement**	**$367,053**	$123,938	$12,288	$77,087	$0	$1,859	$282	$108,879	$0	$42,717	$3	$0	$0

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
APCU October Update
Effective June 1, 2018

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	Adjustments to Base Revenue	Percent Change Base to Base Revenue	1st Pass Adjustment to Proposed Base NPSE Revenue	1st Pass Total Adjustments to Proposed Base NPSE Revenue	1st Pass Percent Change Base to Base Revenue	1st Pass Proposed Base NPSE Revenue	Revised APCU Rates for 2018 October Update ($/kWh)
	Uniform Tariff Rates:															
1	Residential Service	1	13,720	191,153,085	$13,256,174	$5,944,979	$19,201,153	$5,114,121	$18,370,295	($830,857)	(4.33)%	$123,938	(706,919)	(3.68)%	$5,238,060	0.027402
2	Small General Service	7	2,540	18,933,523	$1,508,938	$481,057	$1,989,995	$507,048	$2,015,986	$25,991	1.31%	$12,288	38,279	1.92%	$519,336	0.027429
3	Large General Secondary	9S	943	118,780,814	$6,239,807	$3,073,866	$9,313,673	$3,180,864	$9,420,671	$106,998	1.15%	$77,087	184,085	1.98%	$3,257,951	0.027428
4	Large General Primary	9P	6	16,359,226	$746,600	$383,657	$1,130,257	$424,115	$1,170,715	$40,458	3.58%		38,429	3.40%	$422,085	0.025801
5	Large General Transmission	9T	1	3,035,328	$124,517	$80,040	$204,557	$76,715	$201,232	($3,325)	(1.63)%	$1,859	(1,466)	(0.72)%	$78,574	0.025886
6	Dusk to Dawn Lighting	15	0	434,123	$98,510	$9,831	$108,341	$11,630	$110,140	$1,799	1.66%	$282	2,081	1.92%	$11,912	0.027439
7	Large Power Primary	19P	6	173,550,380	$6,406,873	$4,322,474	$10,729,347	$4,492,707	$10,899,580	$170,233	1.59%	$108,879	279,111	2.60%	$4,601,586	0.026514
8	Large Power Transmission	19T	1	106,832,451	$4,020,341	$2,124,262	$6,144,603	$2,694,615	$6,714,957	$570,353	9.28%		208,917	3.40%	$2,333,178	0.021840
9	Agricultural Irrigation Service	24	1,988	65,829,824	$4,795,387	$1,632,112	$6,427,499	$1,762,669	$6,558,056	$130,557	2.03%	$42,717	173,274	2.70%	$1,805,387	0.027425
10	Unmetered General Service	40	2	5,388	$217	$327	$544	$144	$361	($183)	(33.65)%	$3	(180)	(33.01)%	$148	0.027433
11	Street Lighting	41	10	902,945	$126,775	$15,859	$142,634	$24,189	$150,964	$8,331	5.84%		4,850	3.40%	$20,708	0.022934
12	Traffic Control Lighting	42	8	22,688	$1,703	$429	$2,132	$608	$2,310	$179	8.38%		72	3.40%	$502	0.022111
13	Total Uniform Tariffs		19,225	695,839,775	$37,325,843	$18,068,893	$55,394,735	$18,289,425	$55,615,268	$220,533	0.40%	$367,053	$220,533	0.40%	$18,289,425	
14	Total Oregon Retail Sales		19,225	695,839,775	$37,325,843	$18,068,893	$55,394,735	$18,289,425	$55,615,268	$220,533	0.40%					

Idaho Power Company
Revenue Spread Exhibit for 2018 APCU March Forecast
Stipulated Revenue Spread

Line No.														
1	2018 March Forecast NPSE = ($0.62)/MWh x 694,276.451 MWhs =	($430,451)												
		TOTAL SYSTEM	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV SECONDARY (9-S)	GEN SRV PRIMARY (9-P)	GEN SRV TRANS (9-T)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	LG POWER TRANS (19-T)	IRRIGATION SECONDARY (24-S)	UNMETERED GEN SERVICE (40)	MUNICIPAL ST LIGHT (41)	TRAFFIC CONTROL (42)
2	April 2018 - March 2019 Generation Level Normalized Sales (kWh)	748,251,156	209,227,304	20,744,179	130,134,511	17,351,238	3,138,528	475,798	183,804,202	110,241,240	72,113,759	5,904	989,628	24,865
3	Class Share of April 2018 - March 2019 Generation Level Normalized Sales (kWh)	100%	27.96%	2.77%	17.39%	2.32%	0.42%	0.06%	24.56%	14.73%	9.64%	0.00%	0.13%	0.00%
4	2018 March Forecast Class Allocated NPSE	$ (430,451)	$ (120,364)	$ (11,934)	$ (74,863)	$ (9,982)	$ (1,806)	$ (274)	$ (105,738)	$ (63,419)	$ (41,485)	$ (3)	$ (569)	$ (14)
5	June 2018 - May 2019 Loss-Adjusted Normalized Sales (kWh)	695,839,775	191,153,085	18,933,523	118,780,814	16,359,226	3,035,328	434,123	173,550,380	106,832,451	65,829,824	5,388	902,945	22,688
6	Proposed APCU Rates for 2018 March Forecast ($/kWh)	(0.00062)	(0.00063)	(0.00063)	(0.00063)	(0.00061)	(0.00059)	(0.00063)	(0.00061)	(0.00059)	(0.00063)	(0.00063)	(0.00063)	(0.00063)
7	Proposed March Forecast Revenue Requirement	($430,451)	($120,364)	($11,934)	($74,863)	($9,982)	($1,806)	($274)	($105,738)	($63,419)	($41,485)	($3)	($569)	($14)
10	APCU Rates for 2017 March Forecast - Order No. 17-165	0.239	0.286	0.234	0.238	0.216	0.243	0.209	0.229	0.183	0.228	0.560	0.162	0.174
11	June 2018 - May 2019 Loss-Adjusted Normalized Sales (kWh)	695,839,775	191,153,085	18,933,523	118,780,814	16,359,226	3,035,328	434,123	173,550,380	106,832,451	65,829,824	5,388	902,945	22,688
12	Base NPSE Recovered under Current APCU Rates	$166,406	$54,750	$4,430	$28,309	$3,533	$737	$91	$39,808	$19,563	$15,031	$3	$146	$4

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

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers	Normalized Energy (kWh)	Current Billed Revenue 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 Base Revenue	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:												
1	Residential Service	1	13,720	191,153,085	$19,230,017	$54,750	$19,284,767	($120,364)	($175,114)	($706,919)	($882,033)	$18,402,734	(4.57)%
2	Small General Service	7	2,540	18,933,523	$1,992,797	$4,430	$1,997,227	($11,934)	($16,364)	$38,279	$21,915	$2,019,142	1.10%
3	Large General Secondary	9S	943	118,780,814	$9,331,252	$28,309	$9,359,561	($74,863)	($103,172)	$184,085	$80,913	$9,440,474	0.86%
	Large General Primary	9P	6	16,359,226	$1,132,678	$3,533	$1,136,211	($9,982)	($13,515)	$38,429	$24,914	$1,161,125	2.19%
	Large General Transmission	9T	1	3,035,328	$205,007	$737	$205,744	($1,806)	($2,543)	($1,466)	($4,009)	$201,735	(1.95)%
4	Dusk to Dawn Lighting	15	0	434,123	$108,405	91	$108,496	($274)	($364)	$2,081	$1,717	$110,213	1.58%
5	Large Power Primary	19P	6	173,550,380	$10,755,033	$39,808	$10,794,841	($105,738)	($145,546)	$279,111	$133,565	$10,928,406	1.24%
	Large Power Transmission	19T	1	106,832,451	$6,160,414	$19,563	$6,179,978	($63,419)	($82,983)	$208,917	$125,934	$6,305,912	2.04%
6	Agricultural Irrigation Service	24	1,988	65,829,824	$6,437,242	$15,031	$6,452,273	($41,485)	($56,516)	$173,274	$116,758	$6,569,031	1.81%
7	Unmetered General Service	40	2	5,388	$545	3	$548	($3)	($6)	($180)	($186)	$362	(33.95)%
8	Street Lighting	41	10	902,945	$142,710	146	$142,856	($569)	($715)	$4,850	$4,134	$146,990	2.89%
9	Traffic Control Lighting	42	8	22,688	$2,135	4	$2,139	($14)	($18)	$72	$54	$2,193	2.53%
10	Total Uniform Tariffs		19,225	695,839,775	55,498,236	166,406	$55,664,642	($430,451)	($596,857)	$220,533	($376,324)	$55,288,317	(0.68)%
11	Total Oregon Retail Sales		19,225	695,839,775	55,498,236	166,406	$55,664,642	($430,451)	($596,857)	$220,533	($376,324)	$55,288,317	(0.68)%

(1) Updated June 2018-May 2019 Test Year