ORDER NO. 26-175

ENTERED May 21, 2026

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 462

In the Matter of IDAHO POWER COMPANY, 2026 Annual Power Cost Update.	ORDER

DISPOSITION: STIPULATION ADOPTED

In this order, we adopt the stipulation entered into by Idaho Power Company and Staff of the Public Utility Commission of Oregon (collectively, the stipulating parties) resolving all issues in this docket.

I. BACKGROUND

On October 31, 2025, Idaho Power filed its 2026 Annual Power Cost Update (APCU). The APCU is an automatic adjustment clause used by Idaho Power to update its net power supply expense (NPSE) included in rates, effective June 1 of each year. The APCU is comprised of an October update and March forecast. Adjustments from the October update are reflected in each schedule's base rates. Adjustments from the March forecast are reflected in Idaho Power Schedule 55.

Idaho Power's 2025 October update resulted in a cost per unit of $35.75 per megawatt-hour (MWh), an increase of $2.76 per MWh from last year's October update rate. Idaho Power then calculated the Oregon jurisdictional share of the total NPSE by multiplying the per MWh cost by the forecasted Oregon jurisdictional loss-adjusted normalized sales for the April 2026 through March 2027 test period, resulting in a revenue increase of approximately $1.86 million. Staff subsequently conducted a thorough investigation of the 2026 October update.

Staff's opening testimony, filed on January 27, 2026, addressed several elements relevant to the APCU, including Idaho Power's energy market, coal, and load forecasts, day-ahead markets, PURPA expenses, battery energy storage system modeling, repricing methodology, hedging, and certain power purchase agreements. Idaho Power filed reply testimony indicating it did not support some of Staff's proposed adjustments.

On March 25, 2026, Idaho Power filed the 2026 APCU March forecast, and noted changes in several variables from the October update, including: (1) fuel process and transportation costs; (2) PURPA expense; (3) forecast of normalized load; (4) forecast of hydro generation from stream flow conditions using the most recent water supply forecast and current reservoir levels; and (5) known power purchases and surplus sales made in compliance with the company's Energy Risk Management Policy. Idaho Power calculated a March forecast rate of $36.67 per MWh, an increase of $2.13 from the 2025 March forecast of $24.54 and indicated that the overall revenue impact of the combined 2026 October update and March forecast was an increase of $1.5 million, or 2.24 percent overall, compared to the APCU amounts currently included in customers' rates. This amount reflected an increase of $1.7 million in base rate revenues associated with the October Update and a $0.2 million decrease in Schedule 55 revenues associated with the March forecast. Staff investigated the March forecast and the parties held settlement conferences in April.

II. STIPULATION

The parties filed a joint stipulation on April 27, 2026. Idaho Power and Staff (stipulating parties) agree to Idaho Power's filed October update and March forecast amounts, subject to a reduction, resulting from an unspecified adjustment to reduce the system-wide 2026 NPSE by $18 million ($0.7 million Oregon -allocated). This adjustment results in a revenue requirement increase of $0.7 million or 1.11 percent overall.[1]

The stipulating parties agree that Idaho Power's allocation methodology conforms to Commission precedent. The stipulating parties further agree that the rate change resulting from the stipulation results in rates that are fair, just, and reasonable, as required by ORS 756.040. Finally, the stipulating parties agree that the result of this stipulation is in conformance with the methodology adopted by the Commission in Order No. 08-238, as modified in subsequent APCU orders. The stipulating parties request that the Commission approve the stipulation as presented and direct that the corresponding rates be effective June 1, 2026, as permitted by the APCU mechanism.

III. RESOLUTION

We review the terms of any stipulation for reasonableness and accord with the public interest. We have reviewed Idaho Power's 2026 Annual Power Cost Update, the terms of the stipulation, the joint supporting brief, and Idaho Power's supporting testimony. We find that the stipulation represents a reasonable and appropriate resolution of this docket

[1] Stipulation at Exhibit 3 (Apr. 27, 2026).

and that it will result in fair, just, and reasonable rates. Accordingly, we adopt the stipulation.

IV. ORDER

IT IS ORDERED that:

1. The stipulation between Idaho Power Company and Staff of the Public Utility Commission of Oregon, filed on April 27, 2026, and attached as Appendix A, is adopted.

2. Idaho Power Company must file new tariffs consistent with this order, reflecting the terms of the stipulation, to be effective June 1, 2026.

Made, entered, and effective May 21 2026.

Letha Tawney
Chair

Les Perkins
Commissioner

Karin Power
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 462

In the Matter of IDAHO POWER COMPANY, 2026 Annual Power Cost Update.	**STIPULATION**

This Stipulation resolves all issues among the parties to Idaho Power Company's ("Idaho Power" or "Company") 2026 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, 2026.

I. PARTIES

1. The parties to this Stipulation are Staff of the Public Utility Commission of Oregon ("Staff") and Idaho Power (together, the "Stipulating Parties").[2]

II. 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 and the

[1] *In the Matter of Idaho Power Company's Application for Authority to Implement a Power Cost Adjustment Mechanism for Electric Service to Customers in the State of Oregon*, Docket No. UE 195, Order No. 08-238 (Apr. 28, 2008).
[2] Idaho Power and Staff are the only parties to Docket No. UE 462.

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

3. On October 31, 2025, Idaho Power filed testimony and exhibits for the 2026 October Update component of the APCU ("2026 October Update").[3] Pursuant to Order No. 08-238, as modified by Order No. 25-194, Idaho Power reviewed all the inputs and provided changes in the 2026 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) Public Utility Regulatory Policies Act of 1978 ("PURPA") contract expenses; and (8) the Oregon state allocation factor. Consistent with Order No. 25-194, Idaho Power no longer utilizes a forward price curve as a variable in the APCU.[4]

4. The test period for the 2026 October Update was April 2026 through March 2027 and included updates to the above-referenced variables for all Company-owned resources and updated sales and load forecasts. The 2026 October Update specifically accounted for changes in coal and natural gas prices, generation and expenses related to contracts entered into pursuant to PURPA, new resources, normalized system load, and hydro modeling.[5]

5. As part of the fuel expense update, the Company updated its forecast of Oil, Handling, and Administrative and General ("OHAG") expenses in accordance with the terms of the 2016 and 2017 APCU settlement stipulations.[6]

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[3] *See* Idaho Power/100-105.
[4] Idaho Power/100, Brady/5.
[5] Idaho Power/100, Brady/6-15.
[6] Idaho Power/100, Brady/6-8. Per the terms of the 2016 APCU settlement stipulation, 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 its coal-fired units. *In the Matter of Idaho Power Company's 2016 Annual Power Cost Update*, Docket No. UE 301, Stipulation at 7 (May 11, 2016). The Company then separately accounted for its proportional share of the total OHAG expense incurred. The settlement stipulation approved in the Company's 2017 APCU required that Idaho Power forecast its proportional share of total OHAG expense

6. The 2026 October Update also included the Company's estimate of benefits associated with participation in the Western Energy Imbalance Market ("EIM").[7] For the 2026 October Update, Idaho Power proposed to include $12.6 million in system EIM benefits, $0.5 million Oregon-allocated, as an offset to NPSE.[8]

7. The filed 2026 October Update resulted in a rate of $35.75 per megawatt-hour ("MWh"), representing an increase of $2.76 relative to last year's October Update rate of $32.99 per MWh.[9]

8. For the 2026 October Update, the Company calculated the Oregon jurisdictional share of total NPSE by multiplying the rate of $35.75 per MWh by the forecasted Oregon jurisdictional loss-adjusted normalized sales for the April through March test period.[10] Idaho Power then calculated the incremental Oregon jurisdictional NPSE by comparing the 2026 October Update Oregon jurisdictional share of total NPSE to the NPSE recovery under current approved rates from the 2025 APCU October Update, resulting in a revenue requirement increase of approximately $1.86 million.[11]

9. The Company's revenue spread methodology for the 2026 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,

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at its coalfired units using a three-year historical average of actual OHAG costs, applying a growth (or reduction) rate based on the five-year historical average trend. *In the Matter of Idaho Power Company's 2017 Annual Power Cost Update*, Docket No. UE 314, Stipulation at 7 (Apr. 28, 2017). However, consistent with the 2024 and 2025 APCU filings, Idaho Power updated the OHAG forecast at Bridger using a three-year historical average of actual OHAG costs and a three-year average growth rate. The Company excluded the growth rate data prior to 2022 due to the change in OHAG beginning in 2021. Starting in 2021, OHAG moved from a positive to a negative number, which is the result of an increase in revenue from fly ash sales. *In the Matter of Idaho Power Company's 2024 Annual Power Cost Update*, Docket No. UE 425, March Forecast at 6 (Idaho Power/300, Brady/6 (Mar. 25, 2024)). Idaho Power also accounted for revenues received from or expenses paid to NV Energy (its ownership partner in the Valmy plant) for use of the Company's unused capacity or the Company's use of NV Energy's unused capacity. Idaho Power/100, Brady/10.

[7] Idaho Power/100, Brady/15-19.
[8] Idaho Power/100, Brady/15.
[9] Idaho Power/100, Brady/22-23.
[10] Idaho Power/100, Brady/25.
[11] Idaho Power/100, Brady/25.

consistent with the stipulation from the 2018 APCU.[12] In addition, consistent with the stipulation from the 2018 APCU, any rate increase resulting from application of this revenue spread methodology as applied to a customer class was capped at 3 percent above the overall average rate increase on a percentage of total revenue basis. However, the cap is not applicable for the 2026 APCU.[13]

10. On December 1, 2025, Idaho Power filed a stipulated proposed procedural schedule that would allow the Public Utility Commission of Oregon ("Commission") to issue an order on Idaho Power's 2026 APCU prior to June 1, 2026.[14] Administrative Law Judge Christopher J. Allwein adopted a schedule similar to the proposed schedule, but with some dates adjusted by one day to accommodate scheduled filings in other dockets.[15]

11. The Stipulating Parties held an initial workshop on February 10, 2026, to discuss the 2026 October Update filing. Staff served discovery on Idaho Power and conducted a thorough investigation of the 2026 October Update.

12. On January 27, 2026, Staff filed Opening Testimony.[16] Staff's testimony addressed the Company's energy market forecasts, day-ahead markets, the load forecast, PURPA expenses, battery energy storage system modeling, the repricing methodology, the coal forecast, hedging, and the Pleasant Valley Solar power purchase agreements.

13. Idaho Power filed Reply Testimony on February 24, 2026.[17]

14. On March 25, 2026, Idaho Power filed the 2026 March Forecast component of the APCU ("2026 March Forecast"). The 2026 March Forecast consisted of direct testimony describing the Company's estimate of the expected NPSE for the upcoming water year—

[12] Idaho Power/100, Brady/25-26; Idaho Power/105.
[13] Idaho Power/100, Brady/26.
[14] Idaho Power Company's Proposed Schedule (Dec. 1, 2025).
[15] Ruling at 1 (Dec. 5, 2025).
[16] Staff/100-101; Staff/200-203; Staff/300-302; Staff/400-402; Staff/500-501; Staff/600-602.
[17] Idaho Power/200.

April 2026 through March 2027.[18] Order No. 08-238, as modified by Order No. 25-194, calls for the March Forecast to update the following variables: fuel prices; transportation costs; wheeling expenses; planned outages and equivalent forced outage rates; heat rates; forecast of normalized sales and loads updated for known significant changes since the October Update; forecast hydro generation; wholesale power purchase and sale contracts; PURPA expenses; and the Oregon state allocation factor.

15. Idaho Power reviewed all the variables for the March Forecast and the following variables changed since the 2026 October Update: (1) fuel prices and transportation costs; (2) PURPA expense; (3) forecast of normalized load; (4) forecast of hydro generation from stream flow conditions using the most recent water supply forecast and current reservoir levels; and (5) known power purchases and surplus sales made in compliance with the Company's Energy Risk Management Policy.[19]

16. The fuel prices were updated to reflect changes in forecast natural gas and coal costs.[20] Total coal fuel expense included in the 2026 March Forecast is $47.8 million, compared to $57.3 million in the 2026 October Update, a decrease of 17 percent.[21] Coal-fired generation also decreased as compared to the October Update, from 1.7 million MWh to 1.3 million MWh, or approximately 20 percent. Forecast coal-fired generation decreased 20 percent from the October Update primarily due to the relative decrease in economics compared to natural gas and market purchases throughout the APCU test year.[22]

17. The updated natural gas price forecast reflected a decrease relative to the 2026 October Update. The gas price forecast used for the March Forecast for Henry Hub was

[18] Idaho Power/300-306.
[19] Idaho Power/300, Brady/4-11.
[20] Idaho Power/300, Brady/4-8.
[21] Idaho Power/300, Brady/5.
[22] Idaho Power/300, Brady/5.

$4.02 per Metric Million British Thermal Unit, which is $0.19 lower than the Henry Hub gas price used for the October Update.[23]

18. The March Forecast also included reduced PURPA generation relative to the October Update. The October Update included 327.3 average megawatts ("aMW") of available PURPA generation, whereas the PURPA generation included in the March Forecast was 326.9 aMW, a decrease of 0.42 aMW, or 0.1 percent.[24] Total PURPA expense included in the March Forecast is $251.2 million, which was the same total PURPA expense included in the October Update.[25] PURPA expense included in the 2026 March Forecast is $0.21 million less than PURPA expense included in the filed 2025 March Forecast and $12.5 million more than PURPA expense included in the settled 2025 March Forecast.[26]

19. The Company also updated its forecast normalized load in the March Forecast. The forecast of system normalized load used for the March Forecast is 2,162 aMW compared to 2,156 aMW for the October Update, an increase of 6 aMW.[27]

20. The Company also updated the hydro forecast.[28] The hydro generation forecasted for this year's March Forecast is 6.5 million MWh compared to 7.2 million MWh in last year's March Forecast, a 9 percent decrease.[29]

21. Idaho Power proposed $14.7 million in system EIM benefits as an offset to NPSE in the 2026 March Forecast. On an Oregon-allocated basis, the EIM benefits totaled $0.6 million.[30]

22. The 2026 March Forecast included forecast NPSE of $611.6 million, compared to the 2025 March Forecast NPSE of $559.8 million.[31] The 2025 March Forecast unit cost

[23] Idaho Power/300, Brady/7.
[24] Idaho Power/300, Brady/9.
[25] Idaho Power/300, Brady/9.
[26] Idaho Power/300, Brady/9.
[27] Idaho Power/300, Brady/9.
[28] Idaho Power/300, Brady/10.
[29] Idaho Power/300, Brady/10.
[30] Idaho Power/300, Brady/14.
[31] Idaho Power/300, Brady/12.

per MWh was $34.54 per MWh, compared to this year's March Forecast unit cost of $36.67 per MWh.[32] The overall revenue impact of the combined 2026 October Update and March Forecast is an increase of $1.5 million, or 2.24 percent overall.[33] The $1.5 million increase reflects an increase of $1.7 million in base rate revenues associated with the October Update and a $0.2 million decrease in Schedule 55 revenues associated with the March Forecast, as compared to what is currently included in Oregon customers' rates related to the 2025 APCU.[34]

23. Staff conducted a thorough investigation of the March Forecast.

24. Settlement conferences were held on February 10, March 2, April 1, and April 7, 2026. Ultimately, the Stipulating Parties resolved all the issues in this case through these discussions, resulting in the settlement stipulation as described in this Agreement.

III. AGREEMENT

25. The Stipulating Parties agree to the filed October Update and March Forecast amounts, subject to a reduction resulting from an unspecified monetary adjustment.

26. Unspecified Monetary Adjustment: For the sole purpose of settling this 2026 APCU, Idaho Power agrees to an unspecified monetary adjustment reducing the system-wide 2026 NPSE by $18.0 million ($0.7 million Oregon-allocated).

27. Based on the agreed-upon adjustment, the Stipulating Parties agree to a revenue requirement increase of $0.7 million or 1.11 percent overall. This revenue requirement is supported by the following exhibits to this stipulation: Exhibit 1 shows the October Update NPSE based on the settlement terms; Exhibit 2 shows the March Forecast NPSE based on the settlement terms; Exhibit 3 shows the Combined Rate based on the settlement terms; and Exhibit 4 shows the rate spread based on the settlement terms.

[32] Idaho Power/300, Brady/15.
[33] Idaho Power/300, Brady/17.
[34] Idaho Power/300, Brady/17.

28. The Stipulating Parties agree that the Company's allocation methodology conforms to Commission precedent, as reflected in previous APCU stipulations, and should be approved. The Stipulating Parties agree that the rate change resulting from the Stipulation results in rates that are fair, just, and reasonable, as required by ORS 756.040.

29. The Stipulating Parties agree that rates agreed to by the terms of this Stipulation should be made effective on June 1, 2026, as permitted by the APCU mechanism.

30. The Stipulating Parties agree the result of this Stipulation is in conformance with the methodology adopted by the Commission in Order No. 08-238, as modified in subsequent APCU orders.

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

32. 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.

33. 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.

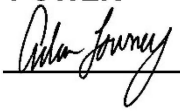
34. The Stipulating Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right, pursuant 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.

35. 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.

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

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

STAFF	**IDAHO POWER**
By: /s/ Stephanie Andrus	By: 
Date: April 27, 2026	Date: April 27, 2026

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 462

Exhibit 1 to Stipulation

October Update Net Power Supply Expense
Based on Settlement Terms

April 27, 2026

ORDER NO. 26-175

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR APRIL 1, 2026 -- MARCH 31, 2027
AURORA Developed Results - 2026 October Update
AVERAGE

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	831,657.6	881,323.0	866,582.9	734,348.7	603,439.6	567,209.1	463,040.1	421,194.9	590,239.1	764,396.1	743,909.7	781,449.3	8,248,790.0
	Bridger Coal													
2	Energy (MWh)	28,220.9	29,161.6	28,220.9	150,965.9	199,573.3	175,975.9	188,795.3	224,782.7	238,079.2	169,974.3	161,030.5	57,256.9	1,652,037.5
3	AURORA Modeled Expense ($ x 1000)	$ 1,507.4	$ 1,557.6	$ 1,507.4	$ 5,204.9	$ 6,662.5	$ 5,930.2	$ 6,337.3	$ 7,401.5	$ 7,823.9	$ 5,467.9	$ 5,151.2	$ 2,271.0	$ 56,822.8
4	AURORA Modeled Handling Expense ($ x 1000)	$ (25.8)	$ (26.7)	$ (25.8)	$ (138.1)	$ (182.6)	$ (161.0)	$ (172.7)	$ (205.7)	$ (217.8)	$ (155.5)	$ (147.3)	$ (52.4)	$ (1,511.6)
5	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 1,533.2	$ 1,584.3	$ 1,533.2	$ 5,343.0	$ 6,845.1	$ 6,091.2	$ 6,510.1	$ 7,607.2	$ 8,041.7	$ 5,623.4	$ 5,298.5	$ 2,323.4	$ 58,334.4
6	IPC Share of OHAG Expense ($ x 1000)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (87.9)	$ (1,054.6)
7	Total Expense ($ x 1000)	$ 1,445.3	$ 1,496.4	$ 1,445.3	$ 5,255.1	$ 6,757.2	$ 6,003.4	$ 6,422.2	$ 7,519.3	$ 7,953.9	$ 5,535.6	$ 5,210.6	$ 2,235.5	$ 57,279.8
	Valmy Gas													
8	Energy (MWh)	57,636.5	49,153.0	65,507.5	73,607.2	75,038.8	65,911.6	72,590.7	64,710.8	43,510.9	44,841.3	61,389.2	69,707.3	743,604.7
9	AURORA Modeled Expense ($ x 1000)	$ 2,212.9	$ 1,822.8	$ 2,506.0	$ 3,393.3	$ 3,562.8	$ 3,053.9	$ 3,237.2	$ 3,550.8	$ 3,409.8	$ 3,754.2	$ 4,261.4	$ 3,206.9	$ 37,972.0
10	Usage Charges Paid to IPC ($ x 1000)	(21.6)	(21.6)	(21.6)	(21.6)	(21.6)	(21.6)	(21.6)	(21.6)	(21.6)	(21.6)	(21.6)	(21.6)	$ (259.3)
11	Total Expense ($ x 1000)	$ 2,191.3	$ 1,801.2	$ 2,484.4	$ 3,371.7	$ 3,541.2	$ 3,032.3	$ 3,215.6	$ 3,529.2	$ 3,388.2	$ 3,732.5	$ 4,239.8	$ 3,185.3	$ 37,712.7
	Bridger Gas													
12	Energy (MWh)	106,046.0	82,978.5	93,147.1	101,148.6	104,962.5	92,095.4	119,542.4	100,217.9	71,312.1	74,803.5	96,555.4	130,077.5	1,172,886.5
13	Expense ($ x 1000)	$ 3,679.0	$ 2,847.7	$ 3,323.1	$ 4,353.6	$ 4,640.3	$ 3,981.6	$ 4,822.5	$ 5,052.0	$ 5,155.4	$ 5,750.6	$ 6,191.2	$ 5,352.9	$ 55,150.0
	Langley Gulch													
14	Energy (MWh)	110,860.6	13,025.3	111,179.7	199,995.7	200,732.6	186,402.8	191,324.9	182,448.6	175,697.9	144,642.3	180,359.8	132,977.4	1,829,647.5
15	Expense ($ x 1000)	$ 2,508.2	$ 298.8	$ 2,611.1	$ 5,469.1	$ 5,792.6	$ 5,143.7	$ 5,316.2	$ 6,441.6	$ 7,886.7	$ 6,993.5	$ 7,601.4	$ 3,988.8	$ 60,051.8
	Danskin													
16	Energy (MWh)	26,255.9	27,231.4	26,375.0	38,054.3	40,062.8	26,350.9	27,179.6	26,312.7	27,146.7	29,689.6	29,164.8	33,403.9	357,227.4
17	Expense ($ x 1000)	$ 888.2	$ 881.2	$ 904.8	$ 1,590.4	$ 1,777.8	$ 1,132.1	$ 1,176.3	$ 1,500.4	$ 2,001.2	$ 2,333.5	$ 2,032.3	$ 1,551.3	$ 17,769.6
	Bennett Mountain													
18	Energy (MWh)	18,122.9	18,799.0	18,228.3	22,612.3	24,456.5	18,184.4	18,785.4	18,142.8	18,768.6	20,351.5	20,160.1	20,808.4	237,420.3
19	Expense ($ x 1000)	$ 602.8	$ 592.3	$ 610.2	$ 927.7	$ 1,062.3	$ 758.3	$ 791.2	$ 1,012.3	$ 1,353.9	$ 1,567.3	$ 1,377.2	$ 953.4	$ 11,608.8
20	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 3,520.6	$ 3,525.4	$ 3,417.9	$ 3,525.4	$ 3,652.1	$ 3,757.8	$ 3,762.5	$ 3,426.5	$ 3,762.5	$ 3,422.6	$ 3,515.9	$ 3,422.6	$ 42,711.7
	Purchased Power (Excluding PURPA)													
21	Market Energy (MWh)	53,083.8	104,058.9	174,057.5	311,576.8	245,377.6	133,460.0	148,006.7	207,546.7	285,637.2	299,751.1	121,714.4	143,530.9	2,227,801.5
22	Elkhorn Wind Energy (MWh)	26,300.5	24,261.8	21,899.4	28,526.7	21,910.2	20,565.3	21,326.6	27,103.2	32,442.7	34,352.6	26,154.5	26,277.7	311,121.2
23	Jackpot Solar Energy (MWh)	26,249.5	30,016.1	31,544.1	36,956.3	31,039.8	25,296.5	19,838.2	10,657.1	6,777.7	8,799.1	14,484.7	21,415.5	263,074.6
24	Neal Hot Springs Energy (MWh)	15,976.1	13,246.1	10,412.6	7,848.0	9,350.2	11,559.9	15,650.0	18,125.5	19,570.2	19,316.1	16,395.7	16,814.1	174,264.3
25	Raft River Geothermal Energy (MWh)	6,494.2	7,353.7	6,980.2	6,821.4	6,971.0	7,024.1	7,841.1	8,231.9	8,673.9	8,651.0	7,967.0	8,386.9	91,396.3
26	Black Mesa Solar Energy (MWh)	8,696.9	9,944.8	10,451.0	12,244.2	10,284.0	8,381.1	6,572.7	3,530.9	2,245.6	2,915.3	4,799.0	7,095.3	87,160.6
27	Franklin Solar Energy (MWh)	20,352.5	24,641.3	27,380.7	28,236.1	25,287.2	22,013.0	16,871.2	10,259.0	9,245.2	10,994.1	13,016.8	18,262.0	226,559.0
28	Pleasant Valley Solar 1 & 2 Energy (MWh)	81,951.0	94,632.1	103,330.7	108,127.2	95,608.5	77,284.4	55,773.1	30,457.3	23,682.1	27,082.4	39,495.7	63,802.3	801,226.7
29	Total Energy Excl. PURPA (MWh)	239,104.4	308,154.7	386,056.1	540,336.6	445,828.4	305,584.2	291,879.5	315,911.7	388,274.6	411,861.6	244,027.7	305,584.5	4,182,604.1
30	Market Expense ($ x 1000)	$ 1,005.3	$ 1,723.6	$ 4,605.8	$ 9,900.6	$ 8,161.1	$ 4,227.2	$ 4,510.6	$ 7,636.1	$ 13,163.3	$ 17,604.0	$ 7,084.2	$ 5,668.5	$ 85,290.1
31	Elkhorn Wind Expense ($ x 1000)	$ 2,099.3	$ 1,936.6	$ 1,748.0	$ 2,277.0	$ 1,748.9	$ 1,641.6	$ 1,702.3	$ 2,163.4	$ 2,589.6	$ 2,742.1	$ 2,087.7	$ 2,097.5	$ 24,834.0
32	Jackpot Solar Expense ($ x 1000)	$ 598.9	$ 684.9	$ 719.7	$ 843.2	$ 708.2	$ 577.2	$ 452.7	$ 243.2	$ 154.7	$ 200.8	$ 330.5	$ 488.6	$ 6,002.6
33	Neal Hot Springs Expense ($ x 1000)	$ 2,065.9	$ 1,712.9	$ 1,346.5	$ 1,014.8	$ 1,209.1	$ 1,494.8	$ 2,023.7	$ 2,343.9	$ 2,530.7	$ 2,497.8	$ 2,120.2	$ 2,174.3	$ 22,534.5
34	Raft River Geothermal Expense ($ x 1000)	$ 465.0	$ 526.6	$ 499.8	$ 488.5	$ 499.2	$ 503.0	$ 561.5	$ 589.5	$ 621.1	$ 619.5	$ 570.5	$ 600.6	$ 6,544.8
35	Black Mesa Solar Expense ($ x 1000)	$ -	$ -	$ 309.0	$ 617.9	$ 309.0	$ 79.4	$ 79.4	$ 92.7	$ 92.7	$ 92.7	$ 92.7	$ -	$ 1,765.5
36	Franklin Solar Expense ($ x 1000)	$ 617.3	$ 747.4	$ 830.5	$ 856.4	$ 767.0	$ 667.7	$ 511.7	$ 311.2	$ 280.4	$ 333.5	$ 394.8	$ 553.9	$ 6,871.5
37	Pleasant Valley Solar Expense 1 & 2 ($ x 1000)	$ 981.5	$ 813.9	$ 4,611.2	$ 8,181.3	$ 5,490.7	$ 2,126.7	$ 1,262.0	$ 1,207.0	$ 1,133.0	$ 816.5	$ 1,011.0	$ 400.9	$ 28,035.7
38	Total Expense Excl. PURPA ($ x 1000)	$ 7,833.2	$ 8,145.8	$ 14,670.5	$ 24,179.8	$ 18,893.0	$ 11,317.5	$ 11,103.9	$ 14,586.8	$ 20,565.4	$ 24,906.7	$ 13,691.6	$ 11,984.2	$ 181,878.6
	Storage													
39	Total Storage (MWh)	(17,538.1)	(17,429.3)	(14,355.7)	(14,894.1)	(14,830.6)	(14,049.8)	(17,043.6)	(15,449.1)	(16,940.4)	(20,803.5)	(18,624.5)	(19,018.1)	(200,976.7)
40	Total Storage Expense ($ x 1000)	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 21,546.0
	Demand Response													
41	Energy (MWh)	-	-	3,793.1	11,157.2	1,798.3	-	-	-	-	-	-	-	16,748.5
42	Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Oregon Solar													
43	Energy (MWh)	73.1	88.6	102.2	98.2	88.9	75.2	68.7	47.6	24.8	36.2	33.5	74.9	811.9
44	Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Surplus Sales													
45	Energy (MWh)	431,509.5	275,801.7	187,916.5	73,957.1	76,312.6	165,712.2	208,622.0	105,706.4	79,968.9	116,009.3	230,139.9	269,357.6	2,221,013.5
46	Revenue ($ x 1000)	$ 14,448.05	$ 8,153.47	$ 7,418.46	$ 3,943.66	$ 4,212.75	$ 8,029.76	$ 10,109.00	$ 5,835.40	$ 4,414.59	$ 6,404.16	$ 12,704.61	$ 9,018.79	$ 94,692.7
47	Surplus Sales - Third Party Transmission Losses ($ x 1000)	$ 696.3	$ 529.7	$ 806.5	$ 985.2	$ 1,065.9	$ 957.3	$ 981.4	$ 1,115.4	$ 1,298.9	$ 1,750.6	$ 1,725.7	$ 1,283.3	$ 13,196.06
48	Marginal Energy Surplus Sales ($ x 1000)	$ 100.3	$ 207.3	$ 317.0	$ 360.7	$ 733.3	$ 959.7	$ 1,367.5	$ 2,046.3	$ 2,340.3	$ 5,043.8	$ 4,391.9	$ 4,686.7	$ 22,554.9
49	Net Power Supply Expenses ($ x 1000)	$ 9,219.6	$ 12,493.8	$ 22,720.9	$ 45,178.7	$ 41,900.0	$ 26,975.3	$ 25,948.1	$ 35,866.5	$ 45,808.9	$ 42,839.3	$ 26,833.3	$ 19,480.8	**$ 355,265.3**
	PURPA													
50	Energy (MWh)	298,046.7	312,350.9	283,329.7	281,816.2	262,255.9	226,750.7	194,671.0	186,042.8	171,750.7	189,430.5	212,233.8	248,372.0	2,867,050.9
51	Cost($ X 1000)	$ 19,436.6	$ 22,901.2	$ 26,240.6	$ 28,752.4	$ 27,969.5	$ 20,709.8	$ 18,228.0	$ 17,719.5	$ 18,051.1	$ 16,223.9	$ 18,839.2	$ 16,162.1	$ 251,234.0
52	EIM Benefits ($ x 1000)													$ 14,653.1
53	Total Net Power Supply Expenses ($ x 1000)	$ 28,656.2	$ 35,395.0	$ 48,961.5	$ 73,931.0	$ 69,869.5	$ 47,685.2	$ 44,176.2	$ 53,586.0	$ 63,860.0	$ 59,063.3	$ 45,672.5	$ 35,643.0	**$ 573,846.2**
														Adjustment $ 18,000.00
54	Net Sales at Customer Level (MWh)	1,131,107	1,137,579	1,326,310	1,645,572	1,874,893	1,663,581	1,331,993	1,193,053	1,308,816	1,452,789	1,356,767	1,254,735	16,677,195
55	Hours in Month	720	744	720	744	744	720	744	721	744	744	672	743	8760
56	Unit Cost / MWH (for PCAM)	$ 25.33	$ 31.11	$ 36.92	$ 44.93	$ 37.27	$ 28.66	$ 33.17	$ 44.92	$ 48.79	$ 40.66	$ 33.66	$ 28.41	**$ 34.41**

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 462

Exhibit 2 to Stipulation

March Update Net Power Supply Expense
Based on Settlement Terms

April 27, 2026

Exhibit 2
UE 462 Stipulation
Page 1 of 1

IPCO POWER SUPPLY EXPENSES FOR APRIL 1, 2026 – MARCH 31, 2027
AURORA Developed Results - 2026 March Forecast

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual	Adjustment
1	Hydroelectric Generation (MWh)	641,667.3	789,797.1	799,717.8	586,963.0	485,276.8	470,503.6	421,622.7	367,152.4	420,643.6	458,526.5	480,016.2	601,157.9	6,523,044.8	
	Bridger Coal														
2	Energy (MWh)	27,584.4	28,503.9	27,584.4	97,091.9	95,539.3	78,847.7	104,992.9	177,914.7	237,532.6	215,704.3	205,752.5	31,624.8	1,328,673.5	
3	AURORA Modeled Expense ($ x 1000)	$ 1,453.0	$ 1,504.3	$ 1,458.7	$ 3,566.2	$ 3,533.7	$ 3,024.5	$ 3,848.3	$ 6,048.4	$ 7,910.8	$ 6,893.4	$ 6,315.6	$ 1,415.8	$ 46,972.8	
4	AURORA Modeled Handling Expense ($ x 1000)	$ (25.2)	$ (26.1)	$ (25.2)	$ (88.8)	$ (87.4)	$ (72.1)	$ (96.1)	$ (162.8)	$ (217.3)	$ (197.4)	$ (188.3)	$ (28.9)	$ (1,215.7)	
5	AURORA Expense less Modeled Handling Expense ($ x 1000)	$ 1,478.3	$ 1,530.4	$ 1,483.9	$ 3,655.1	$ 3,621.1	$ 3,096.6	$ 3,944.4	$ 6,211.2	$ 8,128.2	$ 7,090.8	$ 6,503.8	$ 1,444.7	$ 48,188.5	
6	IPC Share of OHAG Expense ($ x 1000)	$ (34.6)	$ (34.6)	$ (34.6)	$ (34.6)	$ (34.6)	$ (34.6)	$ (34.6)	$ (34.6)	$ (34.6)	$ (34.6)	$ (34.6)	$ (34.6)	$ (415.2)	
7	Total Expense ($ x 1000)	$ 1,443.7	$ 1,495.8	$ 1,449.3	$ 3,620.5	$ 3,586.5	$ 3,062.0	$ 3,909.8	$ 6,176.6	$ 8,093.6	$ 7,056.2	$ 6,469.2	$ 1,410.1	$ 47,773.3	
	Valmy Gas														
8	Energy (MWh)	25,273.0	22,501.9	55,867.6	80,392.9	75,832.4	70,781.2	74,484.6	52,764.5	28,922.9	-	1,122.9	8,274.5	496,218.3	
9	AURORA Modeled Expense ($ x 1000)	$ 544.8	$ 484.2	$ 1,216.0	$ 2,329.1	$ 2,409.5	$ 2,137.9	$ 2,346.8	$ 2,348.5	$ 1,929.4	$ -	$ 81.6	$ 338.9	$ 16,166.6	
10	Usage Charges Paid to IPC ($ x 1000)	(20.2)	(20.2)	(20.2)	(20.2)	(20.2)	(20.2)	(20.2)	(20.2)	(20.2)	(20.2)	(20.2)	(20.2)	$ (242.0)	
11	Total Expense ($ x 1000)	$ 524.6	$ 464.0	$ 1,195.8	$ 2,309.0	$ 2,389.3	$ 2,117.8	$ 2,326.6	$ 2,328.3	$ 1,909.2	$ (20.2)	$ 61.4	$ 318.7	$ 15,924.6	
	Bridger Gas														
12	Energy (MWh)	91,722.8	84,147.7	118,918.2	183,891.5	188,233.1	179,938.7	171,379.9	93,878.6	-	-	-	3,637.9	1,115,748.3	
13	Expense ($ x 1000)	$ 1,836.4	$ 1,742.6	$ 2,327.4	$ 4,753.4	$ 5,301.1	$ 4,769.5	$ 4,787.0	$ 3,756.7	$ -	$ -	$ -	$ 139.5	$ 29,413.7	
	Langley Gulch														
14	Energy (MWh)	108,496.2	99,816.2	191,752.1	212,869.6	215,292.3	205,256.8	218,502.4	212,416.7	219,853.0	216,244.4	197,932.3	183,426.6	2,281,858.6	
15	Expense ($ x 1000)	$ 1,658.5	$ 1,568.6	$ 3,034.8	$ 4,269.2	$ 4,624.5	$ 4,211.7	$ 4,639.6	$ 5,783.0	$ 8,191.2	$ 8,432.2	$ 7,021.2	$ 4,189.6	$ 57,624.2	
	Danskin														
16	Energy (MWh)	-	1,254.3	133,768.2	181,256.1	182,884.6	158,616.1	166,075.9	70,527.5	-	-	-	-	894,382.7	
17	Expense ($ x 1000)	$ -	$ 22.7	$ 2,523.0	$ 4,674.1	$ 5,101.3	$ 4,187.5	$ 4,568.4	$ 2,596.1	$ -	$ -	$ -	$ -	$ 23,673.0	
	Bennett Mountain														
18	Energy (MWh)	-	1,254.3	99,498.1	118,618.6	121,459.7	111,307.8	112,381.5	54,581.6	-	-	-	-	619,101.5	
19	Expense ($ x 1000)	$ -	$ 22.7	$ 1,849.4	$ 3,004.0	$ 3,331.4	$ 2,897.1	$ 3,039.3	$ 2,010.8	$ -	$ -	$ -	$ -	$ 16,154.7	
20	Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 3,734.0	$ 3,734.0	$ 3,677.2	$ 3,734.0	$ 3,906.7	$ 3,971.1	$ 3,971.1	$ 3,777.8	$ 3,971.1	$ 2,787.4	$ 3,734.0	$ 3,677.2	$ 44,675.5	
	Purchased Power (Excluding PURPA)														
21	Market Energy (MWh)	71,795.4	62,456.2	56,157.1	161,200.5	165,923.9	47,438.9	73,216.0	236,851.3	495,019.9	477,072.1	287,686.5	274,921.6	2,409,539.2	
22	Elkhorn Wind Energy (MWh)	25,995.9	24,641.4	25,014.8	24,862.9	19,533.5	20,311.3	22,902.2	27,623.5	30,504.5	34,490.5	26,814.7	29,546.9	312,242.2	
23	Jackpot Solar Energy (MWh)	26,713.6	33,377.6	35,653.2	35,740.0	30,105.3	24,563.5	18,881.7	10,769.9	6,951.1	8,519.7	12,466.4	19,434.4	263,176.3	
24	Neal Hot Springs Energy (MWh)	15,976.1	13,246.1	10,412.6	7,848.0	9,350.2	10,904.6	15,254.3	17,183.6	18,978.4	19,316.1	16,395.7	16,836.7	171,702.3	
25	Raft River Geothermal Energy (MWh)	6,494.2	7,353.7	6,980.2	6,821.4	6,971.0	7,090.7	7,869.9	7,739.7	8,295.0	8,651.0	7,967.0	8,398.2	90,631.9	
26	Black Mesa Solar Energy (MWh)	9,056.8	11,316.1	12,087.6	12,117.0	10,206.7	8,327.8	6,401.5	3,651.4	2,356.7	2,888.4	4,226.5	6,588.9	89,225.4	
27	Franklin Solar Energy (MWh)	21,489.4	26,017.8	28,910.2	29,813.3	26,699.7	23,242.6	17,813.6	10,832.0	9,761.7	11,608.2	13,743.9	19,282.1	239,214.3	
28	Pleasant Valley Solar 1 & 2 Energy (MWh)	50,880.3	94,347.7	103,020.0	107,802.7	95,324.4	77,056.5	55,608.2	30,366.6	23,611.3	27,001.5	39,377.8	63,611.7	768,008.6	
29	Total Energy Excl. PURPA (MWh)	228,401.6	272,756.5	278,235.5	386,205.9	364,114.6	218,936.0	217,947.2	344,818.0	595,478.6	589,547.5	408,678.3	438,620.4	4,343,740.1	
30	Market Expense ($ x 1000)	$ 592.3	$ 429.0	$ 4,678.8	$ 8,119.9	$ 8,541.2	$ 5,068.8	$ 1,564.6	$ 7,546.8	$ 23,267.8	$ 21,293.4	$ 12,554.6	$ 5,180.8	$ 98,837.9	
31	Elkhorn Wind Expense ($ x 1000)	$ 1,515.9	$ 1,436.9	$ 1,984.4	$ 2,366.9	$ 1,859.6	$ 1,611.3	$ 1,816.8	$ 2,629.7	$ 2,904.0	$ 2,818.1	$ 2,190.9	$ 1,774.5	$ 24,909.1	
32	Jackpot Solar Expense ($ x 1000)	$ 607.9	$ 759.5	$ 811.3	$ 813.3	$ 685.1	$ 559.0	$ 429.7	$ 245.1	$ 160.5	$ 196.8	$ 287.9	$ 448.9	$ 6,004.9	
33	Neal Hot Springs Expense ($ x 1000)	$ 1,519.6	$ 1,260.0	$ 1,351.2	$ 1,222.2	$ 1,456.1	$ 1,415.1	$ 1,979.6	$ 2,676.0	$ 2,955.5	$ 2,543.0	$ 2,158.5	$ 1,624.7	$ 22,161.5	
34	Raft River Geothermal Expense ($ x 1000)	$ 340.4	$ 385.4	$ 497.8	$ 583.7	$ 596.5	$ 505.6	$ 561.2	$ 662.3	$ 709.8	$ 620.6	$ 571.6	$ 442.8	$ 6,477.7	
35	Black Mesa Solar Expense ($ x 1000)	$ -	$ -	$ 309.0	$ 617.9	$ 309.0	$ 79.4	$ 79.4	$ 92.7	$ 92.7	$ 92.7	$ 92.7	$ -	$ 1,765.5	
36	Franklin Solar Expense ($ x 1000)	$ 641.0	$ 776.0	$ 879.4	$ 906.8	$ 812.1	$ 707.0	$ 541.8	$ 329.5	$ 296.9	$ 353.1	$ 418.0	$ 586.5	$ 7,248.1	
37	Pleasant Valley Solar Expense 1 & 2 ($ x 1000)	$ 579.5	$ 811.2	$ 4,603.6	$ 8,169.7	$ 5,479.9	$ 2,119.8	$ 1,257.9	$ 1,136.2	$ 929.9	$ 867.3	$ 1,094.9	$ 455.4	$ 27,505.3	
38	Total Expense Excl. PURPA ($ x 1000)	$ 5,796.5	$ 5,858.1	$ 15,115.4	$ 22,800.4	$ 19,739.4	$ 12,066.0	$ 8,230.9	$ 15,318.3	$ 31,317.2	$ 28,784.9	$ 19,369.1	$ 10,513.7	$ 194,909.8	
	Storage														
39	Total Storage (MWh)	(10,435.6)	(11,003.7)	(15,289.7)	(14,805.4)	(14,632.0)	(15,196.7)	(19,071.9)	(14,840.1)	(15,150.6)	(17,513.1)	(13,492.5)	(15,933.8)	(177,365.0)	
40	Total Storage Expense ($ x 1000)	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 1,795.5	$ 21,546.0	
	Demand Response														
41	Energy (MWh)	-	-	5,319.7	11,386.1	297.0	-	-	-	-	-	-	-	17,002.8	
42	Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
	Oregon Solar														
43	Energy (MWh)	73.1	88.6	102.2	98.2	88.9	75.2	68.7	47.6	24.8	36.2	33.5	74.9	811.9	
44	Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
	Hedges														
45	Energy (MWh)	-	-	-	45,552.0	32,800.0	6,992.0	-	-	3,120.0	49,200.0	-	-	137,664.0	
46	Cost($ X 1000)	$ -	$ -	$ -	$ 2,693.03	$ 1,943.40	$ 346.10	$ -	$ -	$ 182.05	$ 3,677.70	$ -	$ -	$ 8,842.28	
	Surplus Sales														
47	Energy (MWh)	149,302.0	174,752.6	297,508.7	102,546.7	98,556.3	223,211.0	345,439.2	92,288.5	72.6	3,917.2	2,971.4	11,896.8	1,502,462.8	
48	Revenue ($ x 1000)	$ 3,748.04	$ 4,430.24	$ 7,999.04	$ 4,369.57	$ 4,484.52	$ 8,600.48	$ 13,310.02	$ 4,199.32	$ 3.30	$ 178.24	$ 135.21	$ 298.65	$ 51,756.6	
49	Surplus Sales - Third Party Transmission Losses ($ x 1000)	$ 414.5	$ 398.7	$ 515.9	$ 835.8	$ 880.0	$ 770.9	$ 841.8	$ 971.0	$ 1,322.9	$ 1,249.3	$ 1,110.0	$ 673.6	$ 9,984.49	
50	Marginal Energy Surplus Sales ($ x 1000)	$ 44.1	$ 149.2	$ 257.8	$ 359.2	$ 604.2	$ 906.8	$ 1,240.5	$ 2,329.2	$ 3,986.7	$ 5,599.5	$ 4,278.6	$ 4,057.2	$ 23,812.9	
51	Net Power Supply Expenses ($ x 1000)	$ 12,582.6	$ 11,725.8	$ 24,195.2	$ 48,088.6	$ 45,750.4	$ 29,146.1	$ 21,875.8	$ 36,043.4	$ 50,147.0	$ 45,486.6	$ 32,926.6	$ 17,014.9	$ 374,983.0	
	PURPA														
52	Energy (MWh)	296,125.7	323,311.8	298,518.9	288,797.8	264,498.3	220,338.1	213,969.8	153,228.4	168,564.5	192,196.4	209,282.8	234,512.1	2,863,344.5	
53	Cost($ X 1000)	$ 19,420.9	$ 22,901.2	$ 26,240.6	$ 28,722.7	$ 28,160.1	$ 20,476.3	$ 17,793.1	$ 17,144.5	$ 18,147.2	$ 16,284.5	$ 18,823.0	$ 17,138.0	$ 251,252.2	
54	EIM Benefits ($ x 1000)													$ 14,653.1	
55	Total Net Power Supply Expenses ($ x 1000)	$ 32,003.5	$ 34,627.0	$ 50,435.8	$ 76,811.3	$ 73,910.5	$ 49,622.4	$ 39,668.9	$ 53,187.9	$ 68,294.2	$ 61,771.2	$ 51,749.7	$ 34,152.9	$ 593,582.0	$ 18,000.00
56	Net Sales at Customer Level (MWh)	1,131,107	1,137,579	1,326,310	1,645,572	1,874,893	1,663,581	1,331,993	1,193,053	1,308,816	1,452,789	1,356,767	1,254,735	16,677,195	
57	Hours in Month	720	744	720	744	744	720	744	721	744	744	672	743	8760	
58	Unit Cost / MWH (for PCAM)	$ 28.29	$ 30.44	$ 38.03	$ 46.68	$ 39.42	$ 29.83	$ 29.78	$ 44.58	$ 52.18	$ 42.52	$ 38.14	$ 27.22	$ 35.59	
		1,259,606.64	1,437,676.12	1,696,484.27	2,075,771.33	1,913,128.66	1,483,185.46	1,336,914.49	1,420,201.46	1,658,916.62	1,700,025.00	1,486,354.68	1,473,498.43	18,941,763.16	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 462

Exhibit 3 to Stipulation

Combined Rate
Based on Settlement Terms

April 27, 2026

Idaho Power Company
2026 APCU Combined Rate Calculation
April 2026 - March 2027

Line		
	OCTOBER UPDATE	
1	Forecast of Normalized Sales (MWh)	16,677,195
2	Total Net Power Supply Expense	$573,846,247
3	October APCU Unit Cost ($/MWh)	$34.41
	MARCH FORECAST	
4	Forecast of Normalized Sales (MWh)	16,677,195
5	Total Net Power Supply Expense	$593,582,022
6	March Forecast Unit Cost ($/MWh)	$35.59
7	Sales Adjusted Forecast Power Cost Change	$19,679,090
8	Portion of Change Allowed	95%
9	Forecast Change Allowed	$18,695,135
10	**March Forecast Rate ($/MWh)**	$1.12
11	**Combined Rate ($/MWh)**	$35.53

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 462

Exhibit 4 to Stipulation

Rate Spread
Based on Settlement Terms

April 27, 2026

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2026

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers [1]	Normalized Energy (kWh) [1]	Current Base Revenue w/o NPSE	Current Base NPSE Revenue	Total Current Base Revenue	2026 October Update Proposed Base NPSE Revenue	Total Proposed Base Revenue	2026 October Update Proposed Adjustments to Base Revenue	2026 October Update Base Revenue Percent Change	Current Billed Revenue w/o March Forecast	Current Billed March Forecast Revenue	Total Current Billed Revenue	2026 March Forecast Proposed Revenue	2026 March Forecast Proposed Adjustments to Billed Revenue	2026 March Forecast Revenue Percent Change	2026 Composite APCU Revenue Adjustment	Proposed Total Billed Revenue	2026 Composite APCU Percent Change
	Uniform Tariff Rates:																			
1	Residential Service	1	14,306	190,938,125	$ 15,531,603	$ 6,373,392	$ 21,904,995	$ 6,647,314	$ 22,178,917	$ 273,922	1.25%	$ 21,899,267	$ 283,992	$ 22,183,258	$ 216,361	$ (67,630)	(0.30)%	$ 206,291	$ 22,389,550	0.93%
2	Residential Service - Time-of-Day Pilot	5	6	152,930	$ 12,073	$ 5,082	$ 17,155	$ 5,324	$ 17,397	$ 242	1.41%	$ 17,150	$ 226	$ 17,377	$ 173	$ (53)	(0.31)%	$ 189	$ 17,566	1.09%
3	Small General Service	7	2,786	20,117,239	$ 1,907,288	$ 671,585	$ 2,578,873	$ 700,456	$ 2,607,744	$ 28,871	1.12%	$ 2,574,146	$ 29,925	$ 2,604,071	$ 22,799	$ (7,126)	(0.27)%	$ 21,745	$ 2,625,816	0.84%
4	Large General Secondary	9S	921	113,660,547	$ 6,480,705	$ 3,794,400	$ 10,275,105	$ 3,957,465	$ 10,438,170	$ 163,065	1.59%	$ 10,248,395	$ 169,075	$ 10,417,470	$ 128,810	$ (40,264)	(0.39)%	$ 122,801	$ 10,540,270	1.18%
5	Large General Primary	9P	8	22,029,501	$ 1,092,568	$ 719,695	$ 1,812,263	$ 750,625	$ 1,843,192	$ 30,929	1.71%	$ 1,807,086	$ 32,069	$ 1,839,155	$ 24,432	$ (7,637)	(0.42)%	$ 23,292	$ 1,862,447	1.27%
6	Large General Transmission	9T	1	2,971,028	$ 123,338	$ 95,050	$ 218,387	$ 99,133	$ 222,471	$ 4,084	1.87%	$ 217,689	$ 4,235	$ 221,924	$ 3,227	$ (1,009)	(0.45)%	$ 3,075	$ 224,999	1.39%
7	Dusk to Dawn Lighting	15	0	130,893	$ 115,798	$ 4,371	$ 120,169	$ 4,558	$ 120,357	$ 188	0.16%	$ 120,138	$ 195	$ 120,333	$ 148	$ (46)	(0.04)%	$ 141	$ 120,475	0.12%
8	Large Power Primary	19P	5	154,028,494	$ 5,972,383	$ 5,033,056	$ 11,005,439	$ 5,249,288	$ 11,221,672	$ 216,233	1.96%	$ 10,969,242	$ 224,268	$ 11,193,510	$ 170,857	$ (53,410)	(0.48)%	$ 162,822	$ 11,356,332	1.45%
9	Large Power Transmission	19T	1	102,467,725	$ 4,116,711	$ 3,278,162	$ 7,394,873	$ 3,419,000	$ 7,535,711	$ 140,838	1.90%	$ 7,370,793	$ 146,071	$ 7,516,865	$ 111,284	$ (34,788)	(0.46)%	$ 106,051	$ 7,622,915	1.41%
10	Agricultural Irrigation Service	24	2,349	74,051,600	$ 6,518,939	$ 2,472,673	$ 8,991,612	$ 2,578,905	$ 9,097,845	$ 106,232	1.18%	$ 8,974,210	$ 110,180	$ 9,084,390	$ 83,940	$ (26,240)	(0.29)%	$ 79,993	$ 9,164,382	0.88%
11	Unmetered General Service	40	2	5,388	$ 249	$ 180	$ 428	$ 188	$ 436	$ 8	1.80%	$ 427	$ 8	$ 435	$ 6	$ (2)	(0.44)%	$ 6	$ 441	1.34%
12	Street Lighting	41	26	322,844	$ 150,657	$ 10,780	$ 161,437	$ 11,243	$ 161,901	$ 463	0.29%	$ 161,362	$ 480	$ 161,842	$ 366	$ (114)	(0.07)%	$ 349	$ 162,191	0.22%
13	Traffic Control Lighting	42	13	34,043	$ 3,061	$ 1,137	$ 4,198	$ 1,186	$ 4,246	$ 49	1.16%	$ 4,190	$ 51	$ 4,240	$ 39	$ (12)	(0.28)%	$ 37	$ 4,277	0.87%
14	Total Uniform Tariffs		20,424	680,910,356	$ 42,025,374	$ 22,459,562	$ 64,484,935	$ 23,424,686	$ 65,450,059	$ 965,124	1.50%	$ 64,364,095	$ 1,000,775	$ 65,364,870	$ 762,443	$ (238,332)	(0.36)%	$ 726,792	$ 66,091,662	1.11%
15	Total Oregon Retail Sales		20,424	680,910,356	$ 42,025,374	$ 22,459,562	$ 64,484,935	$ 23,424,686	$ 65,450,059	$ 965,124	1.50%	$ 64,364,095	$ 1,000,775	$ 65,364,870	$ 762,443	$ (238,332)	(0.36)%	$ 726,792	$ 66,091,662	1.11%
																	Filed Increase	$ 1,462,004		2.24%
																	Difference	$ (735,212)		(1.12)%

(1) Updated June 2026-May 2027 Test Year