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October 29, 2026

VIA EMAIL TO

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
Salem, Oregon 97301-3398

Re: Docket No. UE 477 – In the Matter of Idaho Power Company, 2027 Annual Power Cost Update.

Attention Filing Center:

Attached for filing in the above-referenced docket, please find Idaho Power Company's Direct Testimony and Exhibits of Jessica G. Brady (Idaho Power/100-105). Please add these individuals to the service list:

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Additionally, please include McDowell Rackner Gibson PC (dockets@mrg-law.com) and Idaho Power Company (dockets@idahopower.com) as interested parties to this proceeding.

An electronic copy of this filing has been served on all parties in docket UE 462, Idaho Power Company's 2026 Annual Power Cost Update.

Please contact this office with any questions.

Sincerely,

A handwritten signature in blue ink, appearing to read 'Hanna Campbell', is written over a light blue horizontal line.

Hanna Campbell
Paralegal
McDowell Rackner Gibson PC

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 477

In the Matter of
Idaho Power Company,
2027 Annual Power Cost Update.

**IDAHO POWER COMPANY
DIRECT TESTIMONY
OF
JESSICA G. BRADY**

October 29, 2026

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I. INTRODUCTION

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

A. My name is Jessica G. Brady. I am employed by Idaho Power Company ("Idaho Power" or "Company") as a Regulatory Consultant in the Regulatory Affairs Department. My business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. Please describe your educational background.

A. In May 2016, I received a Bachelor of Science degree in Economics and a Bachelor of Arts degree in Spanish from the University of Idaho. I have also attended "The Basics: Practical Regulatory Training for the Electric Industry," an electric utility ratemaking course offered through New Mexico State University's Center for Public Utilities, "Electric Utility Fundamentals & Insights," an electric utility course offered through the Western Energy Institute, and Edison Electric Institute's "Electric Rates Course" offered at the University of Wisconsin-Madison.

Q. Please describe your business experience.

A. In September 2021, I accepted a position at Idaho Power as a Regulatory Analyst in the Regulatory Affairs Department. I was promoted to Senior Regulatory Analyst in October 2023 and to Regulatory Consultant in October 2025. As a Regulatory Consultant, I am responsible for running the AURORA model ("AURORA"), an hourly economic dispatch model, to calculate net power supply expenses ("NPSE"). AURORA is used for ratemaking purposes, as well as in the determination of the marginal cost of energy used in the Company's marginal cost analyses. My duties also include testifying on behalf of Idaho Power in Annual Power Cost Update ("APCU") and other power supply cost-related proceedings, as well as providing analytical support for regulatory activities within the Regulatory Affairs Department.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the determination of the Company's 2027 October Update, the first portion of the Company's APCU. If approved, the 2027 October Update will result in a revenue increase of approximately \$1.16 million, or a 1.74 percent increase in base revenue collection, to become effective June 1, 2027.

Q. How is your testimony organized?

A. My testimony begins with a brief history of the APCU, and the filing requirements associated with it. Next, my testimony describes the required updates to AURORA and the resulting modeling outputs. I then present and discuss the total NPSE for the 2027 October Update and how it compares to last year's 2026 October Update. My testimony concludes with the quantification of the projected revenue requirement and the proposed rate implementation to recover that revenue requirement.

Q. Have you prepared exhibits for this proceeding?

A. Yes. I am sponsoring the following exhibits:

1. Exhibit 101, Total Normalized Base NPSE
2. Exhibit 102, Energy Imbalance Market Benefits
3. Exhibit 103, Year-Over-Year Differences in October Update NPSE
4. Exhibit 104, Revenue Spread
5. Exhibit 105, Revenue Impact

II. APCU OVERVIEW

Q. What is the APCU?

A. The APCU is a rate mechanism that has two components, an October Update and a March Forecast. The October Update establishes the prospective “base” or “normal” power supply expenses for an April through March test period by modeling multiple historical water conditions. For the 2027 October Update, the Company modeled 33 historical water conditions (1991–2023), consistent with the updated hydro modeling developed as part of

1 the ongoing 2027 Integrated Resource Plan ("IRP") process, as discussed later in my
2 testimony. The March Forecast estimates expected power supply expenses over the same
3 test period using a single forecast water condition.

4 The results of the October Update are reflected as an update to base rates, while
5 the results of the March Forecast are reflected in the March Forecast Rate Adjustment
6 listed in Schedule 55. Both rate adjustments go into effect on June 1 of each year.

7 **Q. What expenses are included in the Company's determination of NPSE?**

8 A. The Company determines NPSE based on fuel expenses (Federal Energy Regulatory
9 Commission ("FERC") Accounts 501 and 547), purchased power expenses (FERC
10 Account 555), and battery energy storage lease expenses (FERC Account 577.4, Energy
11 Storage Rents), less surplus sales revenues (FERC Account 447).

12 **Q. What regulatory actions led to the implementation of the APCU?**

13 A. In the final order issued in Idaho Power's 2005 general rate case, docket UE 167, the
14 Commission specifically recognized the Company's unique reliance on hydro generation
15 and its extended amortization of deferred costs, and therefore, directed the parties to work
16 together to "consider whether there is a more effective regulatory mechanism for Idaho
17 Power to recover its allowable power costs."¹ Following that order, the Company filed its
18 request for a power cost adjustment mechanism ("PCAM"). The result of that filing was a
19 settlement stipulation approved by the Commission in Order No. 08-238, establishing the
20 APCU and implementation of the PCAM, or the annual power supply expense true-up.²

21 **Q. What is the purpose of the APCU?**

22 A. The APCU was implemented to adjust rates on an annual basis to capture variability in
23 power supply expenses that occur with a predominantly hydro-based generation fleet. The

¹ *In the Matter of Idaho Power Company Application for General Rate Increase in the Company's Oregon Annual Revenues*, Docket No. UE 167, Order No. 05-871 at 7 (July 28, 2005).

² *In the Matter of Idaho Power Company Application for Authority to Implement a Power cost Adjustment Mechanism for Electric Service Customers in the State of Oregon*, Docket No. UE 195, Order No. 08-238 (April 28, 2008).

APCU mechanism more closely aligns the power supply expenses included in customer rates with the Company's anticipated power supply expenses. Prior to the APCU, the Company would defer excess power supply expenses and then amortize them at a later time for collection, which led to multiple deferrals and long amortization periods.

Q. What are the general requirements for the APCU described in Order No. 08-238?

A. Order No. 08-238 directed the Company to model its power supply expenses using the AURORA model and identified a number of variables that were to be updated annually in AURORA. The specific variables are discussed in the following section.

Q. What is the AURORA model?

A. The AURORA model is a comprehensive electric resource dispatch model that simulates the economic dispatch of the Company's resources to determine NPSE for the APCU. The Commission has also accepted the use of AURORA to determine NPSE for general rate cases, marginal cost analyses, and resource modeling for the Company's IRP.

III. AURORA MODEL INPUTS AND MODELING RESULTS

Q. What are the specific variables that are updated during each APCU filing?

A. Commission Order No. 08-238 identified the following power supply expense variables to be updated annually:

- a. Fuel prices and transportation costs
- b. Wheeling expenses
- c. Planned outages and forced outage rates
- d. Heat rates
- e. Forecast of normalized load and normalized sales
- f. Contracts for wholesale power and power purchases and sales
- g. Forward price curve
- h. Public Utility Regulatory Policies Act of 1978 ("PURPA") contract expenses
- i. The Oregon state allocation factor

1 The Company reviewed all the inputs and updated those that have changed since
2 last year's October Update, as described in more detail in the following sections.

3 **Q. Have there been any changes to the required variables since Commission Order**
4 **No. 08-238?**

5 A. Yes. Commission Order No. 25-194 from the Company's 2025 APCU filing removed the
6 requirement to reprice the AURORA-generated volumes of purchased power and surplus
7 sales with an average forward electric price curve.³ Accordingly, the Company no longer
8 updates or provides the forward price curve for this purpose as part of its APCU filings.

9 **A. Coal Fuel Expense**

10 **Q. Please describe the changes to coal fuel expense and coal-fired generation that**
11 **have occurred since last year's October Update filing.**

12 A. Total coal fuel expense decreased from last year's October Update, from \$57.3 million to
13 \$54.2 million, a decrease of approximately 5 percent. Coal-fired generation increased from
14 last year's October Update, from 1.65 million megawatt-hours ("MWh") to 1.72 million
15 MWh, an increase of approximately 4 percent.

16 **Q. What is driving the increase in year-over-year coal-fired generation?**

17 A. The approximately 4 percent increase in forecast coal-fired generation is primarily driven
18 by a 7 percent decrease in the modeled coal price compared to last year's October
19 Update, making coal-fired generation more economic.

20 **Q. How did the changes in coal fuel expense and coal-fired generation impact the cost**
21 **of coal-fired generation on a per-unit basis?**

22 A. The average per-unit cost of coal-fired generation for the 2027 October Update is
23 \$31.44 per MWh, compared to \$34.67 per MWh for the 2026 October Update. The

³ *In the Matter of Idaho Power Company's 2025 Annual Power Cost Update*, Docket No. UE 444, Order No. 25-194 (May 22, 2025).

1 decrease reflects lower modeled coal fuel costs despite the increase in forecast coal-fired
2 generation.

3 **Q. How does Idaho Power account for Oil, Plant Handling, and Administrative and**
4 **General (“OHAG”) expenses in the 2027 October Update?**

5 A. Idaho Power accounts for OHAG expenses consistent with the settlement stipulations
6 approved in the 2016 and 2017 APCU dockets.

7 The 2016 settlement stipulation established how OHAG expenses are reflected in
8 AURORA. Specifically, the per-MWh OHAG expense included in the model reflects the
9 portion of OHAG expenses associated with dispatching the Company’s coal-fired units.
10 After the modeled dispatch is complete, the Company separately accounts for its
11 proportional share of total OHAG expenses.⁴

12 The 2017 settlement stipulation established the methodology for forecasting the
13 Company’s proportional share of total OHAG expenses. Under that methodology, the
14 forecast is based on a three-year historical average of actual costs, adjusted by a growth
15 (or reduction) rate calculated using the five-year historical average trend.⁵ Consistent with
16 the 2024 through 2026 APCU filings, however, Idaho Power uses a three-year average
17 growth rate for Bridger to exclude data prior to 2022. This reflects the change in OHAG
18 expenses beginning in 2021, when increased fly ash sales revenues caused OHAG to
19 shift from a positive to a negative value.

20 **Q. Have you prepared an exhibit that illustrates the calculation of OHAG expenses for**
21 **the 2027 APCU?**

22 A. Yes. Exhibit 101, Lines 3 through 7, illustrates the calculation of OHAG expenses for
23 Bridger Units 3 and 4.

⁴ *In the Matter of Idaho Power Company’s 2016 Annual Power Cost Update*, Docket No. UE 301, Order No. 16-206 (May 31, 2016).

⁵ *In the Matter of Idaho Power Company’s 2017 Annual Power Cost Update*, Docket No. UE 314, Order No. 17-165 (May 16, 2017).

B. Natural Gas Fuel Expense

Q. Have any changes in natural gas expense and generation occurred since last year's October Update filing?

A. Yes. Natural gas expense in this year's October Update is \$156.6 million, compared to \$225.0 million in 2026, a decrease of approximately 30 percent. Natural gas generation in this year's October Update is 3.5 million MWh compared to 4.3 million MWh in 2026, a decrease of approximately 19 percent.

Q. Please explain the decrease in natural gas generation in this year's October Update.

A. The 19 percent decrease in natural gas generation is primarily due to the relative decrease in economics compared to market purchases during the winter months, as well as the addition of new resources, which I will discuss later in my testimony.

Q. How is the Henry Hub gas price forecast used as an AURORA input?

A. The Company uses the Henry Hub gas price forecast as the starting point in the AURORA model. Henry Hub serves as the reference fuel in AURORA, meaning that other natural gas market prices are derived by applying an adjustment, or "basis," factor to the Henry Hub price. These prices are expressed in dollars per million British thermal units ("MMBtu").

Q. How does the Henry Hub price forecast for the 2027 October Update compare to last year's October Update?

A. The average Henry Hub price used for the 2027 October Update is \$3.68 per MMBtu compared to \$4.21 per MMBtu used in the 2026 October Update. This represents a decrease of \$0.53 per MMBtu, or approximately 13 percent.

Q. Please explain the Idaho, Bridger, and Valmy gas prices.

A. The Idaho gas price represents the cost of gas delivered to Langley Gulch, Danskin, and Bennett Mountain, based on the Henry Hub price with adjustments for the Sumas and Stanfield bases and transportation costs.⁶

The Bridger gas price represents the cost of gas delivered to Bridger Units 1 and 2, based on the Henry Hub price with adjustments for the Rockies basis and transportation costs.

Similarly, the Valmy gas price represents the cost of gas delivered to Valmy Units 1 and 2, also based on the Henry Hub price with adjustments for the Rockies basis and transportation costs.

Q. How do the Idaho, Bridger, and Valmy gas prices for the 2027 October Update compare to last year?

A. Please see Table 1 below. All prices are in dollars per MMBtu.

Table 1: Gas Price Comparison

	2027 October Update	2026 October Update	Difference
Idaho	\$3.45	\$4.03	(\$0.58)
Bridger	\$3.55	\$4.08	(\$0.53)
Valmy	\$3.57	\$4.13	(\$0.56)

Q. What is driving the decrease in prices as compared to last year?

A. The decrease in all three prices is primarily due to the lower Henry Hub price forecast compared to last year's October Update. Elevated natural gas storage inventories nationally and in the West have also contributed to downward pressure on natural gas prices.

⁶ Idaho Citygate Price based on a 20/80 Sumas/Stanfield split, which aligns with available transport capacity in the APCU year.

1 **Q. How does Idaho Power account for revenues and expenses associated with**
2 **ownership partner use of unused capacity at Valmy?**

3 A. Consistent with the settlement stipulation approved in the 2017 APCU, Idaho Power
4 includes a three-year historical average of net revenues or expenses associated with
5 ownership partner use of unused capacity at Valmy in its determination of NPSE.⁷

6 For the 2027 October Update, the Company included \$242,002 in net revenues
7 associated with NV Energy's use of Idaho Power's unused capacity as an offset to NPSE,
8 as shown on Line 13 of Exhibit 101. The three-year historical average will be updated as
9 part of the 2027 March Forecast.

10 **C. PURPA Expense**

11 **Q. How has the annual PURPA generation changed from last year's October Update?**

12 A. The 2027 October Update includes 2.83 million MWh of PURPA generation. Last year's
13 October Update included 2.87 million MWh, which represents a decrease of approximately
14 34,000 MWh, or 1.2 percent.

15 **Q. How has the annual PURPA expense changed from last year's October Update?**

16 A. The 2027 October Update forecasts PURPA expense of \$258.2 million. Last year's
17 October Update forecasted \$251.2 million, which represents an increase of \$6.9 million,
18 or 3 percent.

19 **D. New Resources**

20 **Q. Have any additional resources been added to the Company's resource portfolio**
21 **since last year's October Update?**

22 A. Yes. The following resources have been added to the AURORA model for this year's
23 October Update:

24 a. Crimson Orchard Solar (100 MW)

⁷ *Id.* at 5.

- b. Crimson Orchard Battery Energy Storage System ("BESS") (100 MW)
- c. Blacks Creek Solar (80 MW)
- d. Blacks Creek Solar (320 MW)

In order to calculate a "base" or "normal" level of net power supply expense, all new resources were modeled as annualized online resources for the entire test year, rather than beginning on their scheduled commercial operation dates. This reflects the same treatment applied to new projects in prior APCU dockets when they were scheduled to come online during an APCU test year.

Q. Can you provide additional details on the new resources and their treatment in the 2027 October Update?

A. Yes.

- a. Crimson Orchard Solar is a 100 MW alternating current solar photovoltaic facility with a 20-year PPA. It is scheduled to come online in June 2027.
- b. Crimson Orchard BESS provides 100 MW of battery storage under a 20-year energy storage agreement. It is scheduled to come online in June 2027. Consistent with the modeling of other BESS resources, Crimson Orchard BESS was modeled to be grid-charged, with its scheduled discharge shaped to the Company's demand, net of "must-run" PURPA and PPA resources.
- c. Blacks Creek Solar (80 MW) is an 80 MW alternating current solar photovoltaic facility with a 25-year PPA. It is scheduled to come online in June 2027.
- d. Blacks Creek Solar (320 MW) is a 320 MW alternating current solar photovoltaic facility with a 20-year PPA. It is scheduled to come online in June 2027. Similar to Pleasant Valley Solar 1 and 2, the PPA was negotiated in conjunction with a special contract with Brisbie, LLC ("Brisbie"), under the Company's Clean Energy Your Way ("CEYW") program. Meta Platforms, Inc. is the parent company of Brisbie. The methodology for forecasting expenses associated with CEYW resources in the October Update NPSE is described later in my testimony.

1 **Q. How are expenses associated with Crimson Orchard BESS included in NPSE?**

2 A. Similar to Kuna BESS, the Crimson Orchard BESS agreement is structured as a tolling
3 arrangement under which the developer owns and operates the facility, while Idaho Power
4 has the exclusive right to dispatch and use the charging and discharging energy in
5 exchange for a fixed monthly payment. The Company has included the monthly contract
6 payments of \$1.22 million in NPSE, which reflects an annual expense of \$14.64 million,
7 as shown on Line 51 of Exhibit 101.

8 ***E. Normalized Load***

9 **Q. Please describe the changes to the Company's system load since last year's**
10 **October Update.**

11 A. The Company's normalized system load used in last year's October Update was
12 2,156 aMW. The Company's normalized system load used in this year's October Update
13 is 2,374 aMW, representing an increase in load of 218 aMW, or 10.1 percent, between the
14 two test years.

15 **Q. Please explain what is driving the increase in the Company's system load.**

16 A. The Company's 10.1 percent increase in system load is due to continued customer growth
17 in Idaho Power's service area as well as anticipated increased loads from large special
18 contract customers.

19 **Q. Does the Company also include revenues from marginal cost-based energy sales**
20 **to special contract customers as an offset to NPSE?**

21 A. Yes. As described in more detail later in my testimony, the Company includes forecast
22 revenues from customers served at a marginal cost-based energy rate as an offset to
23 NPSE. These revenues are included in Exhibit 101, Line 59.

24 **Q. How are third-party transmission losses handled in the Company's load forecast?**

25 A. Consistent with the 2024 through 2026 APCU filings, Idaho Power included third-party
26 transmission losses in the Company's load forecast. Third-party transmission losses

1 represent the additional electricity that Idaho Power generates in each hour to offset losses
2 associated with third parties wheeling power through Idaho Power's transmission system.
3 The average hourly load required to serve third-party transmission losses is approximately
4 36 MW.

5 **Q. Does the Company also include the associated revenues from third-party**
6 **transmission losses as an offset to total NPSE?**

7 A. Yes. The Company has included revenues received from third-party transmission losses
8 as an offset to NPSE. These revenues were calculated by multiplying Idaho Power's
9 annual average marginal resource price, as determined by the AURORA model, by the
10 annual energy associated with the approximately 36 MW of third-party transmission
11 losses. Line 58 of Exhibit 101 shows the total revenue associated with third-party
12 transmission losses.

13 ***F. Hydro Modeling***

14 **Q. Please describe the Company's hydro modeling process.**

15 A. Idaho Power uses RiverWare, a river and reservoir modeling decision support system, to
16 simulate reservoir operations and flows at each of the Company's hydroelectric projects
17 and estimate available hydropower production given water resource constraints. The
18 resulting hydro generation estimates are used as inputs to AURORA.

19 The Company adopted RiverWare for the 2022 October Update to replace its then-
20 existing modeling tools. Idaho Power procured the RiverWare Planning Model from the
21 U.S. Bureau of Reclamation to model the Snake River Basin from the headwater basins
22 downstream to Brownlee Reservoir inflow. The Company also worked with RiverWare
23 developers to develop a model of the Hells Canyon Complex that incorporates reservoir
24 operating logic.

1 **Q. What changes were made to the hydro modeling for this year's October Update, and**
2 **why?**

3 A. Forecast hydro generation for the 2027 October Update was derived from updated hydro
4 modeling developed as part of the ongoing 2027 IRP process. These updates were made
5 to reflect current hydrologic conditions and include the following:

- 6 a. Updated groundwater response functions and present-conditioning to align
7 modeled reach gains with current levels.
- 8 b. Updated managed recharge infrastructure capacity based on the most recent
9 estimates from the Idaho Water Resource Board ("IWRB").
- 10 c. Updated recharge logic to simulate the Milner bypass agreement with the IWRB.
- 11 d. Updated the hydrology period of record ("POR") from 1981–2017 (37 water years)
12 to 1991–2023 (33 water years).

13 Collectively, these changes update the representation of groundwater conditions,
14 managed recharge activities, and historical hydrology used to forecast hydroelectric
15 generation.

16 **IV. BASE NET POWER SUPPLY EXPENSES**

17 **A. *Energy Imbalance Market ("EIM") Benefits and Costs***

18 **Q. Has the Company adjusted the 2027 October Update NPSE to reflect Idaho Power's**
19 **participation in the Western EIM?**

20 A. Yes. The 2027 October Update includes the incremental benefits associated with Idaho
21 Power's participation in the Western EIM. Incremental costs associated with Idaho
22 Power's participation in the Western EIM are no longer included in the APCU, as these
23 costs were included in the Company's last general rate case, for which updated rates went
24 into effect October 15, 2024.⁸

⁸ *In the Matter of Idaho Power Company's Request for a General Rate Revision*, Docket No. UE 426, Order No. 24-311 at 1 (Sep. 23, 2024).

1 **Q. What level of EIM benefits is Idaho Power proposing to include in the 2027 October**
2 **Update?**

3 A. Idaho Power is proposing to include \$20.0 million in system EIM benefits, or approximately
4 \$0.8 million on an Oregon-jurisdictional basis, as an offset to NPSE.

5 **Q. How does this compare to the level of EIM benefits included in last year's APCU**
6 **filing?**

7 A. Compared to the \$14.7 million included in the 2026 October Update, this year's level of
8 benefits has increased by approximately 37 percent.

9 **Q. Please describe the Company's approach to forecasting EIM benefits.**

10 A. The Company uses the most recent twelve months of actual data to forecast EIM benefits.
11 Idaho Power begins with the California Independent System Operator's ("CAISO") EIM
12 benefit calculation and applies two hydro-related adjustments, as described below. For the
13 2027 October Update, the forecast is based on September 2025 through August 2026
14 historical data.

15 **Q. Why do EIM benefits vary from year to year?**

16 A. EIM benefits are influenced by natural gas prices, regional hydro conditions, and real-time
17 market price spreads. Changes in these conditions can result in year-over-year
18 differences in benefits.

19 **Q. How does CAISO quantify EIM benefits?**

20 A. CAISO uses a counterfactual methodology to estimate how an EIM Balancing Authority
21 Area ("BAA") would have operated without participating in the EIM. The counterfactual
22 dispatch moves units inside the BAA to meet real-time imbalances based on economic
23 merit order, without importing or exporting through EIM transfers. CAISO's quantification
24 of total estimated EIM benefits is the cost savings of the EIM dispatch compared to the
25 counterfactual without EIM dispatch. In order to determine both EIM dispatch costs and
26 counterfactual costs, CAISO relies upon bid prices submitted by EIM entities.

1 **Q. What concerns does the Company have regarding CAISO's EIM benefits**
2 **methodology as it relates specifically to Idaho Power?**

3 A. CAISO's methodology uses submitted resource bids to represent dispatch costs.
4 However, Idaho Power's hydro bids reflect operational considerations and do not
5 necessarily represent the economic value of hydro generation for purposes of calculating
6 market benefits.

7 Idaho Power utilizes various pricing tiers for its hydro resources to protect the water
8 from overuse in the market and to adhere to regulated water management requirements.
9 The pricing tiers are based upon certain operational parameters and can result in high bid
10 prices when it is necessary to cease or limit water flows for a particular hydro resource's
11 market participation.

12 Because these higher bid prices reflect operational constraints rather than the
13 underlying cost of hydro generation, using them directly in the benefit calculation can
14 overstate the resulting benefits. Idaho Power therefore applies two adjustments to the
15 hydro pricing cost structure for purposes of calculating EIM benefits: the Zero-Cost
16 Adjustment and the Net Hydro Import/Export Adjustment.

17 **Q. Please describe the changes Idaho Power made to the hydro pricing cost structure**
18 **for purposes of the EIM benefit calculation.**

19 A. The Zero-Cost Adjustment sets hydro dispatch costs to zero in both the counterfactual
20 and EIM dispatch cost calculations to remove the impact of hydro bid prices that reflect
21 operational constraints rather than dispatch costs. The Net Hydro Import/Export
22 Adjustment then applies the Powerdex Mid-Columbia ("Mid-C") hourly market price to the
23 net hydro import or export position in each hour. This adjustment accounts for the market
24 value of net hydro energy imports and exports that would otherwise be valued at zero
25 under the first adjustment.

1 **Q. Did Idaho Power prepare an exhibit to illustrate the adjustments to the hydro pricing**
2 **cost structure of the EIM benefit calculation?**

3 A. Yes. Exhibit 102 illustrates the Company's adjustments to CAISO's EIM benefit calculation
4 for September 2025 through August 2026. Column A shows CAISO's reported benefits of
5 \$33.1 million. Column B reflects the Zero-Cost Adjustment, reducing the estimated
6 benefits to \$21.9 million. Column C reflects the Net Hydro Import/Export Adjustment,
7 resulting in a further reduction of \$1.9 million. Column D shows the final estimated EIM
8 benefits of \$20.0 million. The resulting \$20.0 million in system EIM benefits, or
9 approximately \$0.8 million on an Oregon-jurisdictional basis, is included as an offset to
10 NPSE in Exhibit 101.

11 ***B. Modeling Results***

12 **Q. Have you prepared an exhibit that summarizes the results of the AURORA model**
13 **with all of the updated inputs described above?**

14 A. Yes. Exhibit 101 shows the results of the AURORA modeling determination of normalized
15 NPSE for the April 2027 through March 2028 test year. It presents average generation
16 output and power supply expenses based on 33 historical water conditions.

17 **Q. Please summarize the sources and disposition of energy shown on Exhibit 101.**

18 A. Hydro generation supplies 7.9 million MWh, equivalent to approximately 38 percent of
19 system load. Thermal generation supplies 5.2 million MWh (Bridger Coal 1.7, Valmy
20 Gas 0.3, Bridger Gas 0.7, Langley Gulch 1.9, Danskin 0.4, and Bennett Mountain 0.3),
21 equivalent to approximately 25 percent of system load.

22 Total purchased power is 8.9 million MWh, equivalent to approximately 43 percent
23 of system load. This includes 3.0 million MWh of market purchases, 3.1 million MWh of
24 PPA generation, and 2.8 million MWh of PURPA generation.

25 After accounting for net storage losses and contributions from demand response
26 and Oregon community solar, total energy available is 21.8 million MWh. Of this amount,

20.9 million MWh are used to serve system load, and 1.0 million MWh are sold as surplus sales.⁹

Q. How are CEYW resources accounted for in the determination of NPSE?

A. Idaho Power's CEYW Construction program allows participating large customers to partner with the Company to develop or procure renewable resources to meet their sustainability goals. Under the program, participating customers are responsible for the full contractual cost of their respective PPAs. Those PPA costs are not included in NPSE for recovery from other retail customers. However, NPSE does include any applicable Renewable Capacity Credits and Excess Generation Credits paid to participating customers to reflect the value these resources provide to the Company's system.

Q. Why are Renewable Capacity Credits and Excess Generation Credits included in NPSE?

A. Although participating customers pay the full cost of their PPAs, the resources also provide capacity and energy that can be used to serve the Company's overall system load.

Renewable Capacity Credits recognize the capacity value these resources provide to the system. Excess Generation Credits reflect the value of energy provided to the system when a resource generates more energy than is needed to serve the participating customer's load in a given hour.

These credits are included in NPSE to reflect the value of the capacity and excess energy available to serve system load.

Q. How are Renewable Capacity Credits determined?

A. Renewable Capacity Credits are determined in accordance with the applicable special contracts and pricing provisions. These include Schedule 26 and Schedule 33, applicable

⁹ Totals may not sum due to rounding.

1 to Micron and Brisbie, respectively,¹⁰ as well as the Second Revised Exhibit 1 to the
2 Second Amendment to the Renewable PPA between Idaho Power Company and the City
3 of Boise.¹¹ The Renewable Capacity Credit amounts reflect the capacity value of the
4 resources, based on the most recently acknowledged IRP at the time of PPA execution,
5 and remain fixed for the duration of the respective PPAs.

6 **Q. How are Excess Generation Credits calculated?**

7 A. Excess Generation Credits apply when generation from a participating customer's CEYW
8 resources exceeds the customer's applicable energy requirements in a given hour.

9 No excess generation is forecast for Black Mesa Solar; therefore, no Excess
10 Generation Credits associated with that project are included in NPSE. For Pleasant Valley
11 Solar 1 and 2 and Blacks Creek Solar (320 MW), the excess generation is valued under
12 the Brisbie special contract at the lower of (1) 85 percent of the Mid-C hourly price forecast,
13 adjusted for non-firm energy, or (2) the actual heavy-load/light-load market price
14 applicable to the hour of excess generation. The excess generation is multiplied by the
15 applicable price to determine the credit included in NPSE.

16 For purposes of the October Update, Idaho Power uses forecast Mid-C market
17 prices from the Company's 2025 IRP, applying the 85 percent factor and non-firm
18 adjustment, to estimate Excess Generation Credits because actual market prices for the
19 test period are not yet available. This results in a forecast Excess Generation Credit of
20 \$23.18 per MWh. The detailed calculation of the \$23.18 per MWh credit will be provided
21 as part of my workpapers.

¹⁰ Idaho Public Utilities Commission No. 30, Tariff No. 101. Schedule 26 (Idaho Power Company Electric Service Rate for Micron Technology, Inc., Boise Idaho) and Schedule 33 (Idaho Power Company Electric Service Rate for Brisbie, LLC.).

¹¹ *In the Matter of Idaho Power Company's Application for Approval of a Clean Energy Your Way Construction Agreement with the City of Boise and the First Amendment Thereto*, IPC-E-24-18, Idaho Power's September 25, 2024, Compliance Filing.

1 **Q. How does the Company account for energy revenues from customers served under**
2 **a marginal cost-based energy rate in the NPSE calculation?**

3 A. Idaho Power has included four customers in its forecast of marginal cost-priced energy
4 revenues for the APCU test year: Lamb Weston (Block 2 Energy), Brisbie (Block 2
5 Energy), Micron Idaho Semiconductor Manufacturing (Triton) LLC, and Chobani, LLC
6 (“Chobani”) (Block 2 Energy).

7 The Company’s proposed energy services agreement with Chobani is pending
8 approval by the Idaho Public Utilities Commission in Case No. IPC-E-26-19. Similar to
9 Lamb Weston, Chobani’s proposed pricing structure includes a Block 2 Energy charge
10 priced at marginal cost. The forecast reflects the proposed pricing structure.

11 Revenues from marginal cost-priced energy sales to these customers are treated
12 as surplus sales and serve as an offset to NPSE. This pricing structure is designed to
13 recover the incremental energy costs associated with serving these customers. They are
14 included in Exhibit 101, Line 59. The calculation of these revenues will be provided as part
15 of my workpapers.

16 **C. *Per-Unit Cost Calculation***

17 **Q. Does the Company adjust the per-unit cost calculation to account for CEYW and**
18 **marginal cost-priced energy sales?**

19 A. Yes. Energy sales to participating CEYW customers associated with their CEYW
20 resources, as well as energy sales billed at marginal cost-based rates, are excluded from
21 the test year sales used in the per-unit cost calculation. This ensures that the per-unit cost
22 reflects only the sales billed under standard retail energy rates.

23 **Q. What is the NPSE per-unit cost when you combine all of the quantifications**
24 **described earlier?**

25 A. Exhibit 101 shows total system NPSE of \$607.7 million and normalized annual sales at
26 the customer level for the April 2027 through March 2028 test year of 16,843,491 MWh,

1 resulting in a per-unit cost for the 2027 October Update of \$36.08 per MWh
2 (\$607.7 million / 16.84 million MWh = \$36.08 per MWh), to become effective on
3 June 1, 2027.

4 **Q. How does the 2027 October Update per-unit cost compare to the amount filed in the**
5 **2026 October Update?**

6 A. The 2027 October Update per-unit cost of \$36.08 is \$0.59 higher than last year's per-unit
7 cost.

8 **Q. Has the Company prepared an exhibit that demonstrates the changes in NPSE as**
9 **compared to last year?**

10 A. Yes. Exhibit 103 compares the differences between the 2026 October Update and the
11 2027 October Update. Column E shows the following:

- 12 a. A decrease in coal expense of \$3.1 million associated with an increase of
13 0.07 million MWh in generation.
- 14 b. A decrease in natural gas expense of \$68.4 million associated with a decrease of
15 0.83 million MWh in generation.
- 16 c. An increase in market purchased power expense of \$32.8 million associated with
17 an increase of 0.79 million MWh.
- 18 d. An increase in PPA expense of \$31.0 million associated with an increase of
19 1.13 million MWh.
- 20 e. An increase in storage expense of \$14.6 million associated with the addition of
21 Crimson Orchard BESS.
- 22 f. An increase in PURPA expense of \$6.9 million associated with a decrease of
23 0.03 million MWh.
- 24 g. A decrease in combined surplus sales and related revenue offsets of \$7.4 million.
- 25 h. An increase in EIM benefits of \$5.4 million, resulting in an additional offset to
26 NPSE.

1 **Q. Can you elaborate more on the changes in generation from the 2026 October Update**
2 **to the 2027 October Update?**

3 A. Yes. Forecast hydro generation decreased by approximately 5 percent, primarily reflecting
4 the updated hydro modeling developed as part of the ongoing 2027 IRP process.
5 Coal-fired generation increased by approximately 4 percent, primarily due to lower
6 modeled coal prices. Natural gas generation decreased by approximately 19 percent,
7 reflecting less favorable economics compared to market purchases during the winter
8 months.

9 Market purchases increased by approximately 35 percent, primarily during the
10 winter months, while PPA generation increased by approximately 58 percent with the
11 addition of Crimson Orchard Solar and the two Blacks Creek Solar resources. Surplus
12 sales volumes decreased by approximately 56 percent.

13 The increase in market purchases and PPA generation helped meet higher system
14 load and offset the decrease in hydro and natural gas generation, resulting in fewer surplus
15 sales.

16 **Q. Are the changes in expenses among resource types consistent with the changes in**
17 **output?**

18 A. Yes. The changes in expenses among resource types generally align with the changes in
19 output, particularly when considering the changes in per-unit costs for each resource. Coal
20 expense decreased despite an increase in generation, reflecting lower modeled coal
21 prices. Natural gas expense decreased with both lower generation and lower gas prices.
22 Market purchased power and PPA expenses increased with higher purchased energy
23 volumes.

24 The decrease in natural gas expense is partially offset by increased market
25 purchased power, PPA, PURPA, and storage expenses. In addition, lower surplus sales

1 volumes reduced off-system sales revenues. However, increased revenues from marginal
2 cost-priced energy sales offset much of the reduction in surplus sales revenues.

3 **Q. Did the Company comply with the methodologies in Order Nos. 08-238 and 25-194**
4 **when it performed its analysis to determine the NPSE for the 2027 October Update?**

5 A. Yes. The Company has complied with the methodologies detailed in Order Nos. 08-238
6 and 25-194 for calculating this year's October Update.

7 ***D. Jurisdictional Allocation of NPSE***

8 **Q. How did the Company calculate the Oregon jurisdictional share of NPSE?**

9 A. The Oregon jurisdictional share of NPSE is calculated by multiplying the system NPSE
10 total per-unit cost of \$36.08 per MWh by the forecast Oregon jurisdictional loss-adjusted
11 normalized sales for the April 2027 through March 2028 test period of 693,085 MWh,
12 resulting in an Oregon jurisdictional share of NPSE of \$25.0 million
13 (\$36.08 x 693,085 MWh = \$25.0 million), as shown on Line 1 of Exhibit 104.

14 ***E. Quantification and Discussion of the APCU Revenue Requirement***

15 **Q. Based on the determination of the Oregon jurisdictional share of NPSE, what is the**
16 **APCU revenue requirement for the 2027 October Update?**

17 A. As shown on Line 1 of Exhibit 104, the APCU revenue requirement for the 2027 October
18 Update is \$25.0 million.

19 **Q. What is the overall base revenue impact of this year's October Update compared to**
20 **current base revenue?**

21 A. Exhibit 104 also shows the revenue impact resulting from this year's October Update. As
22 shown on Line 10, Base NPSE recovery under currently approved APCU rates is
23 \$23.85 million, whereas the proposed 2027 APCU October Update revenue requirement
24 is \$25.0 million, as shown on Line 1. The comparison of this year's October Update to
25 current approved revenue indicates an increase in Oregon base revenue of approximately
26 \$1.16 million, or 1.74 percent.

V. RATE IMPLEMENTATION

Q. What method of allocation did the Company use to spread the APCU revenue requirement associated with the 2027 October Update to the various customer classes?

A. The Company allocated the \$25.0 million APCU revenue requirement associated with the 2027 October Update using the revenue spread methodology agreed upon in the settlement stipulation approved by Order No. 18-170. Order No. 18-170 established a revenue spread methodology whereby the total APCU revenue requirement is allocated to individual customer classes on the basis of normalized jurisdictional forecast sales at the generation level for the test period.

The agreed upon revenue spread methodology also included a provision that any rate increases resulting from application of this methodology to a customer class would be capped at 3 percent above the overall average rate increase on a percentage of total revenue basis. This cap was implemented to recognize that the movement to the new methodology could result in relatively large increases for individual classes within a single year. The cap is not applicable for the 2027 APCU.

Q. Have you provided exhibits with the proposed revenue spread and revenue impact resulting from the 2027 October Update?

A. Yes. Exhibit 104 provides the proposed revenue spread, and Exhibit 105 shows the resulting revenue impact.

Q. Does the Company intend to provide supporting workpapers for the 2027 October Update?

A. Yes. Idaho Power will provide its supporting workpapers as part of the 2027 APCU filing. The Company intends to provide these workpapers within five business days of filing the 2027 October Update.

1 VI. CONCLUSION

2 Q. Does this conclude your testimony?

3 A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 477

Exhibit 101

Total Normalized Base NPSE

October 29, 2026

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR APRIL 1, 2027 -- MARCH 31, 2028
AURORA Developed Results - 2027 October Update
AVERAGE

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	792,629.8	856,722.7	854,769.0	701,124.0	568,538.8	518,407.3	439,281.8	382,190.3	536,143.9	741,467.4	747,916.1	729,547.8	7,868,738.9
	Bridger Coal													
2	Energy (MWh)	13,711.6	26,580.7	28,032.4	160,577.6	205,146.3	184,410.5	188,391.2	221,458.8	237,532.6	193,985.0	180,843.5	83,287.4	1,723,957.4
3	AURORA Modeled Expense (\$ x 1000)	\$ 672.6	\$ 1,232.9	\$ 1,346.3	\$ 4,958.6	\$ 6,159.4	\$ 5,567.7	\$ 5,688.7	\$ 6,556.9	\$ 7,005.0	\$ 5,877.0	\$ 5,522.8	\$ 2,904.7	\$ 53,492.8
4	AURORA Modeled Handling Expense (\$ x 1000)	\$ (8.9)	\$ (17.3)	\$ (18.2)	\$ (104.2)	\$ (193.1)	\$ (119.7)	\$ (122.3)	\$ (143.7)	\$ (154.2)	\$ (125.9)	\$ (117.4)	\$ (54.1)	\$ (1,118.8)
5	AURORA Expense less Modeled Handling Expense (\$ x 1000)	\$ 681.5	\$ 1,250.1	\$ 1,364.5	\$ 5,062.8	\$ 6,292.6	\$ 5,687.4	\$ 5,811.0	\$ 6,700.7	\$ 7,159.2	\$ 6,002.9	\$ 5,640.2	\$ 2,958.8	\$ 54,611.6
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)	\$ 646.9	\$ 1,215.5	\$ 1,329.9	\$ 5,028.2	\$ 6,258.0	\$ 5,652.8	\$ 5,776.4	\$ 6,666.1	\$ 7,124.6	\$ 5,968.3	\$ 5,605.6	\$ 2,924.2	\$ 54,196.4
	Valmy Gas													
8	Energy (MWh)	18,945.1	24,807.4	34,874.8	33,820.3	33,401.6	35,060.4	53,312.5	48,046.7	1,525.1	-	-	8,919.2	292,713.0
9	AURORA Modeled Expense (\$ x 1000)	\$ 539.2	\$ 620.4	\$ 992.8	\$ 1,334.7	\$ 1,393.3	\$ 1,334.7	\$ 1,941.5	\$ 2,214.7	\$ 134.2	\$ -	\$ -	\$ 406.5	\$ 10,965.7
13	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)
14	Total Expense (\$ x 1000)	\$ 519.0	\$ 600.2	\$ 972.6	\$ 1,314.5	\$ 1,373.2	\$ 1,368.1	\$ 1,921.3	\$ 2,194.6	\$ 114.1	\$ (20.2)	\$ (20.2)	\$ 386.4	\$ 10,723.7
	Bridger Gas													
15	Energy (MWh)	19,088.5	32,592.8	55,907.6	96,719.8	101,817.6	92,573.3	135,027.0	117,729.3	-	1.8	-	2,059.7	653,517.4
16	Expense (\$ x 1000)	\$ 530.1	\$ 829.4	\$ 1,503.5	\$ 3,433.5	\$ 3,852.7	\$ 3,327.8	\$ 4,484.2	\$ 4,961.0	\$ -	\$ 0.7	\$ -	\$ 92.1	\$ 23,015.1
	Langley Gulch													
17	Energy (MWh)	45,665.9	12,767.3	148,690.8	207,691.7	207,431.1	202,351.1	212,586.8	211,851.4	217,971.6	178,032.8	181,466.8	77,873.3	1,904,380.5
18	Expense (\$ x 1000)	\$ 813.0	\$ 210.5	\$ 2,687.0	\$ 5,071.5	\$ 5,299.9	\$ 5,006.7	\$ 5,206.0	\$ 6,285.0	\$ 6,641.0	\$ 7,628.9	\$ 7,288.1	\$ 2,192.0	\$ 56,329.5
	Danskin													
19	Energy (MWh)	-	-	18,762.6	70,717.1	108,453.1	67,609.4	80,673.9	41,894.8	-	-	-	-	388,110.9
20	Expense (\$ x 1000)	\$ -	\$ -	\$ 412.0	\$ 2,322.6	\$ 3,751.6	\$ 2,234.3	\$ 2,622.6	\$ 1,693.5	\$ -	\$ -	\$ -	\$ -	\$ 13,036.5
	Bennett Mountain													
21	Energy (MWh)	-	-	13,671.2	47,369.7	75,122.7	47,644.7	55,709.7	29,415.1	-	-	-	-	268,932.9
22	Expense (\$ x 1000)	\$ -	\$ -	\$ 300.0	\$ 1,544.8	\$ 2,576.2	\$ 1,572.4	\$ 1,806.5	\$ 1,192.9	\$ -	\$ -	\$ -	\$ -	\$ 8,992.8
23	Fixed Capacity Charge - Gas Transportation (\$ x 1000)	\$ 3,654.0	\$ 3,754.9	\$ 3,654.0	\$ 3,759.6	\$ 3,764.4	\$ 3,649.2	\$ 3,764.4	\$ 3,654.0	\$ 3,759.6	\$ 3,764.4	\$ 3,538.8	\$ 3,764.4	\$ 44,481.5
	Purchased Power (Excluding PURPA)													
24	Market Energy (MWh)	85,803.1	121,270.7	168,335.9	295,573.7	266,765.4	142,810.3	128,966.4	269,389.9	547,408.2	450,269.5	230,272.9	309,024.7	3,015,890.5
25	Elkhorn Wind Energy (MWh)	25,288.6	23,970.9	24,334.1	24,186.4	19,002.0	19,758.6	22,279.0	26,871.9	29,674.5	33,552.0	27,680.8	28,742.9	305,341.7
26	Jackpot Solar Energy (MWh)	27,020.4	33,760.9	36,062.6	36,150.5	30,451.1	24,845.6	19,098.6	10,893.6	7,030.9	8,617.5	13,208.8	19,657.5	286,798.0
27	Neal Hot Springs Energy (MWh)	14,945.5	12,018.5	10,412.6	7,848.0	9,350.2	10,904.5	15,254.3	17,207.4	18,978.4	18,980.6	16,834.8	15,787.5	168,532.5
28	Raft River Geothermal Energy (MWh)	6,369.7	7,700.7	6,980.2	6,821.4	6,971.0	7,090.7	7,869.9	7,750.5	8,295.0	8,622.3	8,190.8	8,204.9	90,967.0
29	Black Mesa Solar Energy (MWh)	8,726.6	10,903.5	11,648.9	11,675.2	9,834.5	8,024.2	6,168.1	3,518.2	2,270.7	2,783.1	4,265.9	6,348.6	86,165.6
30	Franklin Solar Energy (MWh)	20,770.6	25,147.5	27,943.1	28,816.0	25,806.5	22,465.1	17,217.7	10,469.7	9,435.1	11,219.9	14,045.6	18,637.1	231,973.9
31	Crimson Orchard Solar Energy (MWh)	22,950.8	27,237.0	29,257.2	30,540.3	26,726.8	20,946.6	15,351.1	8,813.7	6,236.3	7,584.5	11,187.2	17,583.0	224,414.3
32	Blacks Creek Solar 80 Energy (MWh)	18,321.8	22,168.0	24,236.6	25,001.1	21,902.9	17,512.3	12,549.8	7,067.7	4,890.3	5,920.6	9,537.2	14,350.3	183,458.5
	CEYW Resource Generation													
33	Pleasant Valley Solar 1 & 2 Energy (MWh)	80,079.8	92,628.9	101,175.3	105,676.0	92,404.1	74,030.6	53,599.3	29,533.7	23,035.8	26,313.3	39,705.5	62,025.5	780,207.8
34	Blacks Creek Solar 320 Energy (MWh)	74,185.4	89,464.7	97,854.6	100,959.5	89,262.6	71,549.6	51,310.3	28,902.5	20,003.7	24,214.8	38,996.3	58,370.8	745,074.7
35	Total Energy Excl. PURPA (MWh)	384,462.3	466,271.3	538,239.0	673,248.1	598,477.0	419,938.1	349,664.4	420,418.8	677,258.9	598,088.0	413,925.9	558,732.6	6,098,724.5
36	Market Expense (\$ x 1000)	\$ 1,009.2	\$ 1,320.4	\$ 6,831.2	\$ 13,031.1	\$ 12,516.4	\$ 7,908.3	\$ 3,050.5	\$ 9,544.1	\$ 26,740.5	\$ 20,026.7	\$ 9,561.1	\$ 6,510.1	\$ 118,049.5
37	Elkhorn Wind Expense (\$ x 1000)	\$ 1,537.3	\$ 1,457.2	\$ 2,012.5	\$ 2,400.3	\$ 1,885.8	\$ 1,634.1	\$ 1,842.5	\$ 2,666.8	\$ 2,945.0	\$ 2,103.7	\$ 1,735.6	\$ 1,324.7	\$ 23,545.4
38	Jackpot Solar Expense (\$ x 1000)	\$ 624.1	\$ 779.8	\$ 832.9	\$ 834.9	\$ 703.3	\$ 573.8	\$ 441.1	\$ 251.6	\$ 164.9	\$ 202.1	\$ 309.7	\$ 460.9	\$ 6,179.0
39	Neal Hot Springs Expense (\$ x 1000)	\$ 1,442.3	\$ 1,159.8	\$ 1,370.8	\$ 1,239.8	\$ 1,477.1	\$ 1,435.6	\$ 2,008.2	\$ 2,718.4	\$ 2,998.2	\$ 2,524.2	\$ 2,237.7	\$ 1,538.2	\$ 22,150.4
40	Raft River Geothermal Expense (\$ x 1000)	\$ 335.9	\$ 406.1	\$ 500.8	\$ 587.3	\$ 508.7	\$ 508.7	\$ 564.6	\$ 667.2	\$ 714.1	\$ 622.3	\$ 591.1	\$ 435.2	\$ 6,533.3
41	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
42	Franklin Solar Expense (\$ x 1000)	\$ 632.2	\$ 765.4	\$ 867.5	\$ 894.6	\$ 801.2	\$ 697.4	\$ 534.5	\$ 325.0	\$ 292.9	\$ 348.3	\$ 436.1	\$ 578.6	\$ 7,173.7
43	Crimson Orchard Solar Expense (\$ x 1000)	\$ 1,178.5	\$ 1,398.6	\$ 1,502.4	\$ 1,568.2	\$ 1,372.4	\$ 1,075.6	\$ 788.3	\$ 452.6	\$ 320.2	\$ 389.5	\$ 574.5	\$ 902.9	\$ 11,523.7
44	Blacks Creek Solar 80 Expense (\$ x 1000)	\$ 819.9	\$ 992.0	\$ 1,084.6	\$ 1,118.8	\$ 980.2	\$ 783.7	\$ 561.6	\$ 316.3	\$ 218.8	\$ 265.0	\$ 426.8	\$ 642.2	\$ 8,209.8
	CEYW Resource Expenses													
45	Pleasant Valley Solar Expense 1 & 2 RCC (\$ x 1000)	\$ -	\$ -	\$ 2,340.4	\$ 4,680.8	\$ 2,340.4	\$ 206.4	\$ 206.4	\$ 740.3	\$ 740.3	\$ 740.3	\$ 740.3	\$ 17.3	\$ 12,753.0
46	Blacks Creek Solar 320 RCC (\$ x 1000)	\$ -	\$ -	\$ 1,076.1	\$ 2,152.1	\$ 1,076.1	\$ 343.3	\$ 343.3	\$ 343.3	\$ 343.3	\$ 343.3	\$ 343.3	\$ -	\$ 8,172.6
47	CEYW Excess Generation Credits (\$ x 1000)	\$ 1,372.4	\$ 1,177.4	\$ 2,651.6	\$ 4,162.1	\$ 3,283.1	\$ 2,218.2	\$ 1,144.1	\$ 493.6	\$ 295.8	\$ 537.2	\$ 1,312.4	\$ 913.4	\$ 19,561.3
48	Total Expense Excl. PURPA (\$ x 1000)	\$ 8,951.7	\$ 9,456.6	\$ 21,379.6	\$ 33,288.1	\$ 28,421.1	\$ 18,197.3	\$ 11,564.5	\$ 18,612.0	\$ 35,866.7	\$ 28,195.2	\$ 18,361.1	\$ 13,323.3	\$ 245,617.2
	Storage													
49	Total Storage (MWh)	(17,722.4)	(18,577.2)	(17,058.1)	(17,346.6)	(16,938.9)	(16,812.4)	(19,862.9)	(15,702.6)	(15,355.0)	(19,134.9)	(17,375.3)	(17,946.2)	(209,832.3)
50	Kuna BESS 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
51	Crimson Orchard BESS Storage Expense (\$ x 1000)	\$ 1,220.0	\$ 1,220.0	\$ 1,220.0	\$ 1,220.0	\$ 1,220.0	\$ 1,220.0	\$ 1,220.0	\$ 1,220.0	\$ 1,220.0	\$ 1,220.0	\$ 1,220.0	\$ 1,220.0	\$ 14,640.0
	Demand Response													
52	Energy (MWh)	-	-	5,242.6	11,074.8	589.6	-	-	-	-	-	-	-	16,907.0
53	Cost(\$ X 1000)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	Oregon Solar													
54	Energy (MWh)	73.1	88.6	102.2	98.2	88.9	75.2	68.7	47.6	24.8	36.2	36.0	74.9	814.4
55	Cost(\$ X 1000)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	Surplus Sales													
56	Energy (MWh)	156,038.2	145,110.6	97,509.2	39,677.8	50,088.2	110,396.1	213,930.8	42,158.3	2,147.8	21,806.5	71,746.6	35,469.2	986,079.2
57	Revenue (\$ x 1000)	\$ 2,539.62	\$ 2,659.09	\$ 2,470.64	\$ 1,930.11	\$ 2,553.40	\$ 4,871.90	\$ 9,440.99	\$ 2,149.15	\$ 109.49	\$ 1,111.65	\$ 3,657.50	\$ 577.28	\$ 34,070.8
58	Surplus Sales - Third Party Transmission Losses (\$ x 1000)	\$ 369.7	\$ 349.8	\$ 497.9	\$ 918.7	\$ 980.5	\$ 873.0	\$ 902.8	\$ 1,080.1	\$ 1,336.3	\$ 1,272.9	\$ 1,137.6	\$ 723.7	\$ 10,443.14
59	Marginal Energy Surplus Sales (\$ x 1000)	\$ 3,523.5	\$ 3,855.2	\$ 4,037.6	\$ 4,684.7	\$ 5,600.7	\$ 5,668.6	\$ 6,574.8	\$ 7,901.3	\$ 9,546.8	\$ 9,737.7	\$ 8,683.2	\$ 8,726.4	\$ 78,540.7
60	Net Power Supply Expenses (\$ x 1000)	\$ 11,697.2	\$ 12,218.5	\$ 28,247.9	\$ 51,244.8	\$ 49,177.8	\$ 32,610.7	\$ 23,242.7	\$ 37,143.9	\$ 47,528.8	\$ 36,430.5	\$ 24,310.7	\$ 15,670.3	\$ 369,523.9

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 477

Exhibit 102

Energy Imbalance Market Benefits

October 29, 2026

IDAHO POWER COMPANY
2027 APCU October Forecast
Energy Imbalance Market Benefit Forecast
Based on September 2025 - August 2026 Historical Data

		(A)	(B)	(C)	(D)
Year	Month	CAISO Benefit	Zero-Cost Adjustment	Hydro Net (Export)/Import Adjustment	Idaho Power EIM Benefit
2025	September	\$ 2,449,403	\$ 1,557,809	\$ (86,490)	\$ 1,471,319
2025	October	\$ 2,648,825	\$ 2,100,404	\$ (269,214)	\$ 1,831,190
2025	November	\$ 2,292,269	\$ 1,332,697	\$ (355,719)	\$ 976,978
2025	December	\$ 2,750,801	\$ 1,688,498	\$ 2,024	\$ 1,690,522
2026	January	\$ 2,501,483	\$ 1,826,319	\$ (80,484)	\$ 1,745,835
2026	February	\$ 1,948,665	\$ 1,975,927	\$ 114,173	\$ 2,090,101
2026	March	\$ 5,379,909	\$ 4,003,792	\$ 205,543	\$ 4,209,336
2026	April	\$ 3,701,691	\$ 2,508,603	\$ 87,303	\$ 2,595,906
2026	May	\$ 2,187,737	\$ 1,170,856	\$ (109,162)	\$ 1,061,694
2026	June	\$ 2,487,848	\$ 1,208,598	\$ (11,726)	\$ 1,196,872
2026	July	\$ 1,616,683	\$ 1,214,971	\$ (870,186)	\$ 344,784
2026	August	\$ 3,177,475	\$ 1,285,169	\$ (484,606)	\$ 800,563
Total		\$ 33,142,790	\$ 21,873,644	\$ (1,858,544)	\$ 20,015,100

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 477

Exhibit 103

Year-Over-Year Differences in October Update NPSE

October 29, 2026

IDAHO POWER COMPANY
YEAR OVER YEAR DIFFERENCES IN AURORA DEVELOPED NPSE
2027 OCTOBER UPDATE

GENERATION					
Line No.	Resource Type	A	B	C	D
		2026 October Update		2027 October Update	
1	Hydro (MWh)	8,248,790	44%	7,868,739	38%
2	Coal (MWh)	1,652,037	9%	1,723,957	8%
3	Natural Gas (MWh)	4,340,786	23%	3,507,655	17%
4	Market Purchased Power (MWh)	2,227,802	12%	3,015,891	14%
5	Purchased Power Agreements (MWh)	1,954,803	10%	3,082,834	15%
6	Storage (MWh)	(200,977)	-1%	(209,832)	-1%
7	Other*	17,560	0%	17,721	0%
8	PURPA (MWh)	2,867,051	15%	2,833,084	14%
9	Surplus Sales (MWh)	(2,221,014)	-12%	(986,079)	-5%
10	System Generation (MWh)	21,107,853		21,840,049	
11	System Load (MWh)	18,886,839	100%	20,853,970	100%
12	System Load (aMW)	2,156		2,374	

GENERATION	
E	F
Difference (MWh)	Difference (%)
(380,051)	-5%
71,920	4%
(833,132)	-19%
788,089	35%
1,128,031	58%
(8,856)	4%
161	1%
(33,966)	-1%
1,234,934	-56%
1,967,131	10%
218	

NPSE						
	A		B	C		D
	Resource Type	2026 October Update		2027 October Update		
13	Hydro (\$ x 1000)	\$0	0%	\$0	0%	
14	Coal (\$ x 1000)	\$57,280	10%	\$54,196	9%	
15	Natural Gas (\$ x 1000)	\$225,005	38%	\$156,579	26%	
16	Market Purchased Power (\$ x 1000)	\$85,290	14%	\$118,049	19%	
17	Purchased Power Agreements (\$ x 1000)	\$96,589	16%	\$127,568	21%	
18	Storage (\$ x 1000)	\$21,546	4%	\$36,186	6%	
19	PURPA (\$ x 1000)	\$251,234	42%	\$258,163	42%	
20	Surplus Sales (\$ x 1000)	-\$130,444	-22%	-\$123,055	-20%	
21	EIM Benefits	-\$14,653	-2%	-\$20,015	-3%	
22	Total System (\$ x 1000)	\$591,846	100%	\$607,672	100%	

NPSE	
E	F
Difference (\$ x 1000)	Difference (%)
\$0	0%
-\$3,083	-5%
-\$68,426	-30%
\$32,759	38%
\$30,979	32%
\$14,640	N/A
\$6,929	3%
\$7,389	-6%
-\$5,362	37%
\$15,825	3%

*Other consists of forecast generation from Demand Response and Oregon Community Solar program

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 477

Exhibit 104

Revenue Spread

October 29, 2026

Idaho Power Company
Stipulated Revenue Spread
2027 October Update

Line No.																
1	Proposed October Update APCU Revenue Requirement \$36.08 per MWh x 693,084.608 MWh	\$25,006,493														
		TOTAL	RESIDENTIAL (1)	RESIDENTIAL TOD PILOT (5)	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 2027 - March 2028 Generation Level Normalized Sales (kWh)	736,194,538	204,088,163	196,762	21,232,930	122,722,134	22,555,567	3,022,533	141,392	162,405,472	111,343,667	88,095,415	5,797.49	348,727.30	35,977.14	
3	Class Share of April 2027 - March 2028 Generation Level Normalized Sales (kWh)	100%	27.72%	0.03%	2.88%	16.67%	3.06%	0.41%	0.02%	22.06%	15.12%	11.97%	0.00%	0.05%	0.00%	
4	2027 October Update Class Allocated Base NPSE	\$25,006,493	\$6,932,311	\$ 6,683	\$721,224	\$4,168,532	\$766,150	\$102,667	\$4,803	\$5,516,465	\$3,782,036	\$2,992,358	\$197	\$11,845	\$1,222	
5	June 2027 - May 2028 Loss-Adjusted Normalized Sales (kWh)	693,233,386	189,735,132	182,927	19,737,356	114,077,555	21,465,264	2,937,350	131,405	154,524,712	108,205,702	81,873,063	5,388	324,096	33,436	
6	Proposed APCU Rates for 2027 October Update (\$/kWh)	0.036072	0.036537	0.036536	0.036541	0.036541	0.035693	0.034952	0.036549	0.035700	0.034952	0.036549	0.036549	0.036549	0.036549	
7	Proposed October Update APCU Revenue Requirement	\$25,006,493	\$6,932,311	\$ 6,683	\$721,224	\$4,168,532	\$766,150	\$102,667	\$4,803	\$5,516,465	\$3,782,036	\$2,992,358	\$197	\$11,845	\$1,222	
8	APCU Rates for 2026 October Update (\$/kWh) - Order No. 26-175	0.034402	0.034814	0.034817	0.034819	0.034818	0.034074	0.033367	0.034826	0.034080	0.033367	0.034826	0.034826	0.034826	0.034826	
9	June 2027 - May 2028 Loss-Adjusted Normalized Sales (kWh)	693,233,386	189,735,132	182,927	19,737,356	114,077,555	21,465,264	2,937,350	131,405	154,524,712	108,205,702	81,873,063	5,388	324,096	33,436	
10	Base NPSE Recovered under Current APCU Rates	\$23,845,589	\$6,605,433	\$ 6,369	\$687,229	\$3,971,985	\$731,399	\$98,009	\$4,576	\$5,266,199	\$3,610,457	\$2,851,294	\$188	\$11,287	\$1,164	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

UE 477

Exhibit 105

Revenue Impact

October 29, 2026

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
APCU October Update
Effective June 1, 2027

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) ⁽¹⁾	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 3.54% Cap	Revenue Requirement Shortfall
Uniform Tariff Rates:													
1	Residential Service	1	14,369	189,735,132	\$15,448,954	\$6,605,433	\$22,054,386	\$6,932,311	\$22,381,264	\$326,878	1.48%	\$326,878	\$0
2	Residential Service - Time-of-Day Pilot	5	9	182,927	\$14,335	\$6,369	\$20,704	\$6,683	\$21,019	\$315	1.52%	\$315	\$0
3	Small General Service	7	2,833	19,737,356	\$1,884,557	\$687,229	\$2,571,787	\$721,224	\$2,605,781	\$33,995	1.32%	\$33,995	\$0
4	Large General Secondary	9S	890	114,077,555	\$6,494,166	\$3,971,985	\$10,466,151	\$4,168,532	\$10,662,698	\$196,547	1.88%	\$196,547	\$0
5	Large General Primary	9P	7	21,465,264	\$1,063,296	\$731,399	\$1,794,695	\$766,150	\$1,829,446	\$34,751	1.94%	\$34,751	\$0
6	Large General Transmission	9T	1	2,937,350	\$122,030	\$98,009	\$220,040	\$102,667	\$224,698	\$4,658	2.12%	\$4,658	\$0
8	Dusk to Dawn Lighting	15	0	131,405	\$115,781	\$4,576	\$120,357	\$4,803	\$120,584	\$226	0.19%	\$226	\$0
9	Large Power Primary	19P	6	154,524,712	\$5,992,438	\$5,266,199	\$11,258,637	\$5,516,465	\$11,508,903	\$250,265	2.22%	\$250,265	\$0
10	Large Power Transmission	19T	1	108,205,702	\$4,327,038	\$3,610,457	\$7,937,495	\$3,782,036	\$8,109,075	\$171,580	2.16%	\$171,580	\$0
11	Agricultural Irrigation Service	24	2,369	81,873,063	\$7,131,318	\$2,851,294	\$9,982,611	\$2,992,358	\$10,123,675	\$141,064	1.41%	\$141,064	\$0
12	Unmetered General Service	40	2	5,388	\$249	\$188	\$436	\$197	\$445	\$9	2.13%	\$9	\$0
13	Street Lighting	41	26	324,096	\$150,624	\$11,287	\$161,910	\$11,845	\$162,469	\$558	0.34%	\$558	\$0
14	Traffic Control Lighting	42	13	33,436	\$3,006	\$1,164	\$4,170	\$1,222	\$4,228	\$58	1.38%	\$58	\$0
15	Total Uniform Tariffs		20,526	693,233,386	\$42,747,791	\$23,845,589	\$66,593,380	\$25,006,493	\$67,754,284	\$1,160,903	1.74%	\$1,160,903	\$0
16	Total Oregon Retail Sales		20,526	693,233,386	\$42,747,791	\$23,845,589	\$66,593,380	\$25,006,493	\$67,754,284	\$1,160,903	1.74%	\$1,160,903	\$0

(1) Updated June 2027-May 2028 Test Year