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October 31, 2023

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Filing Center
P.O. Box 1088
201 High Street S.E., Suite 100
Salem, OR 97308-1088

Re: Docket UE 425 – Idaho Power Company’s 2024 Annual Power Cost Upgrade (APCU)

Attention Filing Center:

Attached for filing in the above-referenced docket is Idaho Power Company's Direct Testimony of Jessica G. Brady and Exhibits of Jessica G. Brady (Idaho Power/100-110). Please direct all communications in this matter to the following individuals:

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An electronic copy of this filing has been served on all parties in Docket UE 414 - In the Matter of IDAHO POWER COMPANY, 2023 Annual Power Cost Update.

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Please contact this office with any questions.

Sincerely,

/s/ Cole Albee

Cole Albee
Paralegal

Attachments:
Cc: UE 414 Service List

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IN THE MATTER OF IDAHO POWER)
COMPANY'S 2024 ANNUAL POWER)
COST UPDATE)
OCTOBER UPDATE)
_____)

IDAHO POWER COMPANY
DIRECT TESTIMONY
OF
JESSICA G. BRADY

October 31, 2023

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

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

5 **Q. Please describe your educational background.**

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

13 **Q. Please describe your business experience.**

14 A. In September 2021, I accepted my current position at Idaho Power as a Regulatory
15 Analyst in the Regulatory Affairs Department. As a Regulatory Analyst, I am
16 responsible for running the AURORA model ("AURORA") to calculate net power
17 supply expenses ("NPSE") for ratemaking purposes, as well as the determination of
18 the marginal cost of energy used in the Company's marginal cost analyses. My duties
19 also include providing analytical support for other regulatory activities within the
20 Regulatory Affairs Department.

21 Prior to Idaho Power, I worked for five years at Clearwater Analytics, a provider
22 of investment accounting and reporting software. I held various roles at Clearwater but
23 was primarily focused on customer success and relationship management. I gained a
24 breadth of knowledge in investments and the use of proprietary software to streamline
25 the operations of a company's finance and accounting teams. I spent my last year at
26

1 Clearwater developing a training program focused on providing new hires with the
2 technical skills to be successful in an operations role.

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

4 A. The purpose of my testimony is to present the determination of the Company's 2024
5 October Update, the first portion of the Company's Annual Power Cost Update
6 ("APCU"). If approved, the 2024 October Update will result in a revenue decrease of
7 \$101,556, or a 0.18 percent decrease in base revenue collection, to become effective
8 June 1, 2024.

9 **Q. How is your testimony organized?**

10 A. My testimony begins with a brief history of the APCU, and the filing requirements
11 associated with it. Next, my testimony describes the required updates to AURORA
12 and the resulting modeling outputs. I then present and discuss the total NPSE for the
13 2024 October Update, and how it compares to last year's 2023 October Update. My
14 testimony then discusses the quantification of the projected revenue requirement and
15 the proposed rate implementation to recover the revenue requirement.

16 **Q. Have you prepared exhibits for this proceeding?**

17 A. Yes. I am sponsoring the following exhibits:

- 18 1. Exhibit 101, AURORA modeled determination of normalized power supply
19 expenses for April 1, 2024 – March 31, 2025
- 20 2. Exhibits 102 – 104, Mid-Columbia Forward Price Curves Discounted for Inflation,
21 Producer Price Index for Electric Power, and Forward Prices Used for Re-Pricing
22 Purchased Power and Surplus Sales
- 23 3. Exhibit 105, Total Normalized Base Power Supply Expenses for the 2024 October
24 Update
- 25 4. Exhibit 106, Energy Imbalance Market Benefits
- 26 5. Exhibit 107, Energy Imbalance Market Costs

1 6. Exhibit 108, Year-Over-Year Differences in Modeled NPSE

2 7. Exhibits 109 – 110, Revenue Spread and Revenue Impact

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APCU Overview

5 **Q. What is the APCU?**

6 A. The APCU is a rate mechanism that has two components, an October Update and a
7 March Forecast. The October Update establishes the prospective “base” or “normal”
8 power supply expenses for an April through March test period. The March Forecast
9 is a forecast of expected power supply expenses over the same test period as the
10 October Update. “Base” or “normal” power supply expenses are calculated by
11 modeling the test period under multiple historical water conditions; in this case, the
12 Company modeled 37 historical water conditions (1981-2017) as discussed later in my
13 testimony. Expected power supply expenses are calculated by modeling the same
14 test period as the October Update, except the power supply expenses are calculated
15 by modeling a single forecast water condition. The results of the October Update are
16 reflected as an update to base rates and the results of the March Forecast are reflected
17 in the March Forecast Rate Adjustment listed in Schedule 55, with both of the rate
18 adjustments going into effect on June 1st of each year.

19 **Q. What is the definition of the term “net power supply expense” as the Company
20 and the Public Utility Commission of Oregon (“Commission”) have used the
21 term historically?**

22 A. The Company and the Commission have used the term “net power supply expense”
23 to refer to the sum of the following Federal Energy Regulatory Commission (“FERC”)
24 accounts: fuel expense (FERC Accounts 501 and 547), and purchased power
25 expenses (FERC Account 555), minus surplus sales revenues (FERC Account 447).
26

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

2 A. In the final order issued in Idaho Power’s general rate case, docket UE 167, the
3 Commission specifically recognized the Company’s unique reliance on hydro
4 generation and its extended amortization of deferred costs, and therefore, directed the
5 parties to work together to “consider whether there is a more effective regulatory
6 mechanism for Idaho Power to recover its allowable power costs.”¹ Following that
7 order, the Company filed its request for a power cost adjustment mechanism
8 (“PCAM”). The result of that filing was a settlement stipulation approved by the
9 Commission in Order No. 08-238², establishing the APCU and implementation of the
10 PCAM, or the annual power supply expense true-up.

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

12 A. The APCU was implemented to adjust rates on an annual basis to capture variability
13 in power supply expenses that occur with a predominantly hydro-based generation
14 fleet. The APCU mechanism closely aligns the power supply expenses included in
15 customer rates with the power supply expenses actually incurred by the Company.
16 Prior to the APCU, the Company would defer excess power supply expenses and then
17 amortize them at a later time for collection, which led to multiple deferrals and long
18 amortization periods.

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

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

23 _____
24 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).

25 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
26 (April 28, 2008).

1 **Q. What is the AURORA model?**

2 A. The AURORA model is a comprehensive electric resource dispatch model that
3 simulates the economic dispatch of the Company's resources to determine NPSE for
4 the APCU. The Commission has also accepted the use of AURORA to determine
5 NPSE for general rate cases, marginal cost analyses, and resource modeling for the
6 Company's Integrated Resource Plan ("IRP").
7

8 **AURORA Model Inputs and Modeling Results**

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

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

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

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

23 **Coal Fuel Expense**

24 **Q. Have any changes in coal fuel expense and coal-fired generation occurred since**
25 **last year's October Update filing?**
26

1 A. Yes. Total coal fuel expense included in the 2024 October Update is \$84.6 million,
2 compared to \$82.1 million in the 2023 October Update, an increase of 3 percent. Coal-
3 fired generation decreased from last year's October Update, from 2.46 million
4 megawatt-hours ("MWh") to 2.08 million MWh, a decrease of 15 percent.

5 **Q. What is driving the decrease in year-over-year coal-fired generation?**

6 A. Forecast coal-fired generation decreased 15 percent compared to last year due to the
7 conversion of Bridger units 1 and 2 to natural gas. Both units are scheduled to be
8 converted to natural gas by summer 2024, and as a result, were modeled as natural
9 gas resources for this test year. This is discussed in more detail later in my testimony.

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

12 A. The average per-unit cost of coal production for the 2024 October Update is \$40.63
13 per MWh, compared to \$33.41 per MWh for the 2023 October Update. At Bridger, the
14 per-unit cost of production increased 11 percent, from \$32.15 per MWh in 2023 to
15 \$35.59 per MWh in this year's October Update. This is primarily due to increases in
16 both the modeled heat rate and coal prices at Bridger.

17 The per-unit cost of production at Valmy decreased in this year's October
18 Update compared to last year. This is primarily a result of fixed costs being spread
19 over increased generation (from 90 MWhs to approximately 468,013 MWh) as well as
20 a 31 percent decrease in forecast coal prices at Valmy.

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1 **Q. Did Idaho Power model Oil, Handling, and Administrative and General (“OHAG”)**
2 **expenses as agreed upon in the settlement stipulations approved in the 2016**
3 **and 2017 APCU dockets?**

4 A. Yes. Per the settlement stipulation approved in the 2016 APCU³, the per-MWh OHAG
5 expense included in the AURORA model has been updated to reflect the amount of
6 OHAG expense driven by Idaho Power’s dispatch of the Bridger and Valmy plants.
7 The Company has separately accounted for its proportional share of the total OHAG
8 expense incurred at both plants. Per the settlement stipulation approved in the
9 Company’s 2017 APCU⁴, Idaho Power’s proportional share of total OHAG expense
10 incurred at both of the coal-fired plants is forecast using a three-year historical average
11 of actual OHAG costs, with a growth (reduction) rate equal to the five-year historical
12 average growth (reduction) rate.

13 **Q. Have you prepared an exhibit that illustrates the calculation of OHAG expenses**
14 **for the 2024 APCU?**

15 A. Yes. Exhibit 101 reflects the AURORA-modeled OHAG expense resulting from Idaho
16 Power’s dispatch, as well as Idaho Power’s fixed ownership share of total OHAG
17 expense at both of its coal-fired plants. This methodology effectively includes in the
18 AURORA dispatch price the true variable component of OHAG driven by the
19 Company’s dispatch of each plant. After the AURORA-modeled dispatch has
20 occurred, the resulting costs are adjusted to align with costs actually incurred by the
21 Company at both of its coal-fired facilities.

24 ³ *In the Matter of Idaho Power Company’s 2016 Annual Power Cost Update*, Docket No. UE 301,
25 Order No. 16-206 (May 31, 2016).

26 ⁴ *In the Matter of Idaho Power Company’s 2017 Annual Power Cost Update*, Docket No. UE 314,
Order No. 17-165. (May 16, 2017).

1 For example, on Exhibit 101, Line 4 illustrates the AURORA-modeled OHAG
2 expense resulting from Idaho Power's dispatch of Bridger. Line 5 is the difference
3 between the total AURORA-modeled expenses, Line 3, and the AURORA-modeled
4 OHAG expense, Line 4, at Bridger ($\$59,734.7 + \$613.7 = \$60,348.4$). Line 6
5 represents the Company's proportional share of total OHAG expenses at Bridger using
6 the stipulated methodology discussed above. Line 7 is the sum of the AURORA-
7 modeled expenses (less the AURORA-modeled OHAG at Bridger, Line 5), and the
8 Company's proportional share of total OHAG, Line 6, ($\$60,348.4 - \$2,863.8 =$
9 $\$57,484.5$). Line 7 reflects the final total NPSE for Bridger. In this case, calculated
10 OHAG at Bridger reduces total expenses due to proceeds from the sale of combustion
11 fly ash. This method is replicated for Valmy as shown on Lines 9-14.

12 **Q. Does Idaho Power's 2024 APCU account for revenues received from or**
13 **expenses paid to NV Energy (its ownership partner in Valmy) for usage of the**
14 **Company's unused capacity or the Company's usage of NV Energy's unused**
15 **capacity?**

16 A. Yes. Per the settlement stipulation approved in the 2017 APCU,⁵ Idaho Power agreed
17 to include the three-year historical average of actual net balances associated with
18 ownership partner use of unused capacity at Valmy as an offset or addition to total
19 NPSE.

20 For the 2024 October Update, the 2020-2022 historical average net revenue
21 paid to Idaho Power associated with NV Energy's dispatch of Idaho Power's unused
22 capacity at Valmy is \$71,106 on a system basis. As shown on Line 13 of Exhibit 101,
23 this amount has been reflected as an offset to NPSE for Valmy for the 2024 October
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26 ⁵ *Id* at 4.

1 Update. The Company will update the three-year historical average as part of the
2 2024 March Forecast.

3 Natural Gas Fuel Expense

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

6 A. Yes. Natural gas expense in this year's October Update is \$163.4 million, compared
7 to \$53.3 million in 2023, an increase of 206 percent. Natural gas generation in this
8 year's October Update is 3.03 million MWh compared to 1.13 million MWh in 2023, an
9 increase of 170 percent.

10 **Q. Please explain the increase in natural gas generation in this year's October**
11 **Update.**

12 A. The 170 percent increase in natural gas generation can be attributed to the increase
13 in capacity related to the conversion of Bridger units 1 and 2 to natural gas, as well as
14 the increase in opportunity to make off-system economic sales. The average
15 AURORA-calculated market price associated with surplus sales in this year's October
16 Update is \$43.29, compared to \$35.56 last year, an increase of 22 percent.

17 **Q. How does the natural gas price forecast for the 2024 October Update compare**
18 **to last year's October Update?**

19 A. The Henry Hub price used for the 2023 October Update was \$5.84 per MMBtu, while
20 the Henry Hub price used in the 2024 October Update is \$3.90 per MMBtu, a decrease
21 of \$1.94 per MMBtu or 33 percent.

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

23 A. The Company uses the gas price forecast for Henry Hub as the starting point in the
24 AURORA model. Henry Hub is considered a reference fuel in AURORA, meaning
25 other gas market prices are determined by applying an adjustment factor to the Henry
26 Hub price. For example, a Henry Hub gas price of \$3.90 per MMBtu applied to a

1 Sumas basis of \$1.54 per MMBtu equals a Sumas gas price of \$5.44 per MMBtu
2 (\$3.90 + \$1.54 = \$5.44). The Company develops a separate gas price for its natural
3 gas units also based upon the Henry Hub gas price forecast.

4 **Q. Please explain the Idaho Citygate price and the Bridger Gas price.**

5 A. The Idaho Citygate price is representative of the gas price delivered to Langley Gulch,
6 Danskin, and Bennett Mountain. It is based on the Henry Hub price and applies
7 adjustments for Sumas basis and transport costs.

8 The Bridger Gas price is representative of the gas price delivered to Bridger
9 units 1 and 2. It is based on the Henry Hub price and applies adjustments for Rockies
10 basis and transport costs.

11 **Q. How does the Idaho Citygate price for the 2024 October Update compare to last
12 year?**

13 A. The average Idaho Citygate price for the 2024 October Update is \$5.21 per MMBtu
14 compared to \$5.63 per MMBtu for the 2023 October Update.

15 **Q. What is driving the decrease in the Idaho Citygate price?**

16 A. The decrease in the Idaho Citygate price for the 2024 October Update is primarily due
17 to a decrease in the Henry Hub price, which is attributable to increased natural gas
18 production and above-average storage inventories, as well as relatively mild-winter
19 temperatures in 2023. According to the U.S. Energy Information Administration (“EIA”),
20 record high levels of U.S. natural gas production have resulted in natural gas
21 inventories well above the 5-year average in 2023.⁶

22 **Q. What is the Bridger Gas price used in this year’s October Update?**

23 A. The average Bridger Gas price for the 2024 October Update is \$4.43 per MMBtu.
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26 ⁶ <https://www.eia.gov/todayinenergy/detail.php?id=57200>

1 PURPA Expense

2 **Q. Please explain any changes in PURPA generation since last year's October**
3 **Update.**

4 A. Last year's October Update included 362.0 average megawatts ("aMW") of PURPA
5 generation, whereas PURPA generation included in the 2024 October Update is 354.7
6 aMW, a decrease of 7.35 aMW, or 2.03 percent. The decrease in PURPA generation
7 is primarily due to normal fluctuations in estimated output from the Company's existing
8 PURPA-contracted facilities.

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

10 A. Forecast PURPA expense in this year's October Update is \$250.3 million, an increase
11 of \$3.0 million, or 1 percent, compared to last year's forecast. Compared to last year's
12 settled PURPA expense amount, this year's PURPA forecast is an increase of \$10.1
13 million, or 4 percent. The increase in forecast annual PURPA expense is primarily a
14 result of updated PURPA contract values, partially offset by decreased forecast
15 generation.

16 New Resources

17 **Q. Have any additional resources been added to the Company's resource portfolio**
18 **since last year's 2023 October Update?**

19 A. Yes. The following resources have been added to the AURORA model for this year's
20 October Update. In order to calculate a "base" or "normal" level of net power supply
21 expense, all new resources were modeled as annualized online resources for the
22 entire test year, reflecting the same treatment applied to new projects in prior APCU
23 dockets when they were scheduled to come online during an APCU test year.

24 a. Bridger Gas

25 b. Franklin Solar

26 c. Franklin Battery Energy Storage System ("BESS")

1 d. 36 Megawatt (“MW”) Hemingway BESS

2 e. Pleasant Valley Solar

3 **Q. Please describe the new resources, including how they were modeled for the**
4 **October 2024 filing.**

5 A. The Bridger Gas resource represents Bridger units 1 and 2 converted to natural gas.
6 As listed in the Company’s 2021 and 2023 IRP Action Plans, Bridger units 1 and 2 will
7 be converted to natural gas by summer 2024. As a result, they were modeled as
8 natural gas resources for the 2024 APCU test year.

9 Franklin Solar is a 100-MW alternating current solar photovoltaic facility that is
10 scheduled to come online June 2024. It is a 25-year Power Purchase Agreement
11 (“PPA”) with Franklin Solar, LLC. Franklin BESS, co-located with Franklin Solar, is a
12 Build Transfer Agreement (“BTA”) with Duke Energy Renewables Solar LLC, providing
13 for a minimum capacity of 60 MW.

14 The 36-MW Hemingway BESS resource represents the addition of 36 MW of
15 Idaho Power-owned battery storage at the Hemingway substation. Both the Franklin
16 BESS and 36-MW Hemingway BESS were modeled so that the scheduled generation
17 of each battery is shaped to the Company’s demand, net of the “must-run” PURPA
18 and PPA resources. In addition, both were modeled to be grid-charged.

19 Pleasant Valley Solar is a 200-MW alternating current solar photovoltaic facility
20 that is scheduled to come online March 2025. It is a PPA that was negotiated in
21 conjunction with a new special contract⁷ with Brisbie, LLC (“Brisbie”). Meta Platforms,
22 Inc. is the parent company of Brisbie. Brisbie’s special contract states that Idaho Power
23 will procure renewable resources to support 100 percent of Brisbie’s operations with
24

25 _____
26 ⁷ A “special contract”—i.e., an individualized tariff schedule—is required for customers with an aggregate power requirement greater than 20 MW in both the Company’s Idaho and Oregon jurisdictions.

1 renewable energy on an annual basis. Pleasant Valley Solar will be connected to the
2 Company's system and will not serve Brisbie directly. However, Brisbie will pay for the
3 full cost of the PPA, as well as Idaho Power retail electric service required to support
4 their load. In addition, Brisbie will receive the value that the Pleasant Valley resource
5 provides Idaho Power's system and will be credited for any PPA generation that
6 exceeds their load in a given hour. Because the Pleasant Valley resource comes
7 online prior to Brisbie's load in December 2025, the expenses associated with
8 Pleasant Valley Solar in this APCU test year represent the excess generation from the
9 PPA, as well as the capacity contribution. Per the terms of the contract, the value of
10 excess generation is defined as the lower of 1) 85 percent of a non-firm Mid-Columbia
11 hourly price forecast, or 2) actual heavy-load, light-load price in the hour of excess
12 generation. Because actual heavy-load, light-load prices are not known for a forecast
13 period, the Company used Pleasant Valley generation-shaped-weighted average
14 monthly non-firm Mid-C market prices from the Company's 2023 IRP as an estimate.

15 Normalized Load

16 **Q. Please describe the changes in the Company's system loads since last year's**
17 **October Update.**

18 A. The Company's normalized system load used in last year's October Update was
19 1,957 aMW. The Company's normalized system load used in this year's October
20 Update is 1,971 aMW, representing an increase in load of 14 aMW, or 0.7 percent,
21 between the two test years.

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

23 A. The 0.7 percent increase in system load is primarily due to the inclusion of third-party
24 transmission losses into the Company's load forecast. Third-party transmission losses
25 represent the additional electricity that Idaho Power generates in each hour in order to
26 offset losses from third parties wheeling through Idaho Power's transmission system.

1 The calculated hourly load required to serve third-party transmission losses is
2 approximately 36 MW. Support for this calculation will be included in the Company's
3 workpapers to be provided after this filing.

4 **Q. Why is Idaho Power proposing to include the additional load required to serve**
5 **third-party transmission losses in its load forecast?**

6 A. As a part of the Company's most recent loss study performed in 2022, Idaho Power
7 identified this additional load requirement that wasn't previously incorporated into its
8 load forecast. With the advent of the Energy Imbalance Market ("EIM"), nearly all
9 wheeling customers settle their losses financially, meaning Idaho Power incurs the
10 cost to generate additional energy to account for these losses, and receives
11 compensation from the third-party wheeling customer commensurate with this cost.
12 This is in contrast to before the EIM, where wheeling customers also had the option to
13 settle their losses physically – meaning the customer would generate or acquire the
14 additional physical energy to account for the losses themselves, resulting in no
15 additional required generation (and no corresponding additional payment) to Idaho
16 Power.

17 As a result of nearly all losses being settled financially, the Company is
18 proposing to incorporate the additional load required to serve third-party transmission
19 wheeling losses into its load forecast, and thus also incorporate the cost of the
20 additional generation into the total NPSE.

21 **Q. Does the Company also include the associated revenue from third-party**
22 **transmission losses as an offset to total NPSE?**

23 A. Yes. The Company has included the offsetting revenues received from third-party
24 transmission losses in its total NPSE calculation. This will be discussed in detail later
25 in my testimony.

26

1 Hydro Modeling

2 **Q. Please describe the changes to the hydro modeling process that occurred in the**
3 **2022 and 2023 APCU October Updates.**

4 A. Idaho Power adopted new software called RiverWare for the 2022 October Update
5 that replaced the then-existing modeling tools. It is an object-oriented, multi-objective
6 river and reservoir modeling decision support system. Unlike the legacy tools, the
7 RiverWare software is widely used, well-funded, and is actively being improved. Idaho
8 Power procured a Snake RiverWare Planning Model, which covers the Snake River
9 Basin from the headwater basins downstream to Brownlee Reservoir inflow, from the
10 U.S. Bureau of Reclamation. Idaho Power also worked with RiverWare developers to
11 develop a model of the Hells Canyon Complex with reservoir operating logic. The
12 RiverWare models simulate reservoir operations, flows at each Idaho Power
13 hydroelectric project, and an estimate of maximum available hydropower production
14 given water resource constraints. With the change from the legacy systems to
15 RiverWare, the hydrology period of record (“POR”) was also updated in the 2022
16 October Update to 1951 - 2017 (67 water years). Idaho Power, Commission Staff, and
17 the Citizens’ Utility Board convened a workshop prior to the filing of the 2022 APCU to
18 discuss the transition to RiverWare, and the stipulation from that case reflected
19 modeling utilizing this new software.

20 Forecast hydro generation in the 2023 October Update was derived from the
21 hydro modeling developed for the 2023 IRP. It included a shortened baseline
22 hydrology POR of 1981 – 2017 (37 water years).

23 **Q. Why were these changes made?**

24 A. These changes were identified as part of a systematic review of modeling processes
25 in advance of the 2023 IRP. The resulting updates to the hydro modeling provide an
26 improved representation of observed hydrogeneration and incorporate the Company’s

1 best understanding of current and future changes to the distribution of hydropower.
2 Additionally, the power generation parameters have been refined to account for
3 tailwater effects and reduced generation efficiency under high flow conditions.

4 The shortened baseline hydrology POR focuses on the most recent years and
5 current hydrologic conditions, while maintaining a sufficient number of years to capture
6 the expected distribution of hydrogeneration. The POR change also allowed the
7 Company to better align with industry standard practices, as federal and other hydro
8 modeling entities use a “30-year normal” analysis period. In addition, the hydrologic
9 modeling updates represent an improved calibration of the hydrologic model from a
10 recent recalibration of key cloud seeding basins, which considered only years after
11 1980.

12 Idaho Power believes these updates result in a hydro modeling process and
13 methodology that will provide a more accurate expectation of available hydro
14 generation considering industry best practices and better capturing more recent
15 forecast impacts, such as model recalibration and climate change.

16 **Q. Has the Company validated the performance of the new hydro model?**

17 A. Yes. Per the settlement stipulation agreed to in the 2022 APCU,⁸ the Company
18 performed a validation of the new hydro model. The model was validated using a
19 baseline model run that represented historical observed cloud seeding operations
20 along with current system operations and groundwater conditions.

21 **Q. Please describe the Company’s process for validating the performance of the
22 new hydro model.**

23 A. It is important to note that the 2023 IRP RiverWare model has been calibrated to
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25 _____
26 ⁸ *In the Matter of IDAHO POWER COMPANY, 2022 Annual Power Cost Update*, Docket No. UE 398.
Order No. 22-191. (May 31, 2022)

1 represent how the current hydropower system would respond to a range of hydrologic
2 variability and therefore is not expected to provide a perfect representation of historical
3 observations. In addition, the RiverWare model does not account for any one-off
4 historical operations or historical maintenance schedules, rather it represents typical
5 operations and maintenance across the system. In other words, power generation
6 simulated by the RiverWare model should be considered an estimate of the total
7 available average megawatts (“aMW”). The model also does not account for
8 operational reserves, load, or market conditions. Hydrologically speaking, the basin
9 has seen significant increases to the diversion capacity of the groundwater recharge
10 network above Milner Dam in recent years. This increased capacity is reflected in the
11 RiverWare model and is another important difference between observed and
12 simulated values.

13 Given that the model is not intended to provide a perfect representation of
14 historical conditions, validation of the planning model involved a two-step process
15 whereby a direct comparison of simulated and observed values of reservoir storage,
16 flow, and power generation were used to check for general goodness of fit and screen
17 for model bias. Discrepancies between observed and simulated values were then used
18 to inform a deeper dive into model logic to determine if the response seen in the
19 simulated record aligned with current operational guidance and system conditions.

20 **Q. What were the results of the analysis?**

21 A. Figure 1 and Figure 2 illustrate a comparison between observed and simulated power
22 generation for the Hells Canyon Complex (“HCC”) and the Idaho Power Hydropower
23 System (“IPC Hydro”), excluding spring generation. Observed generation is shown in
24 black, and simulated generation is shown in red. Idaho Power believes these results
25 provide sufficient validation of the updated modeling process.
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Figure 1: Observed vs Simulated Monthly aMW - HCC

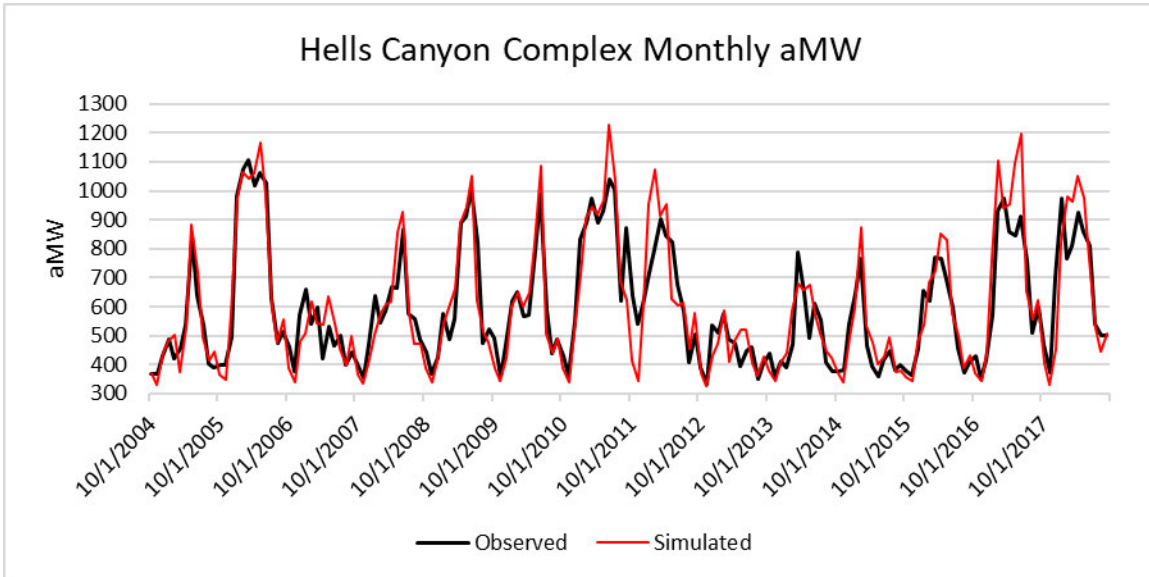
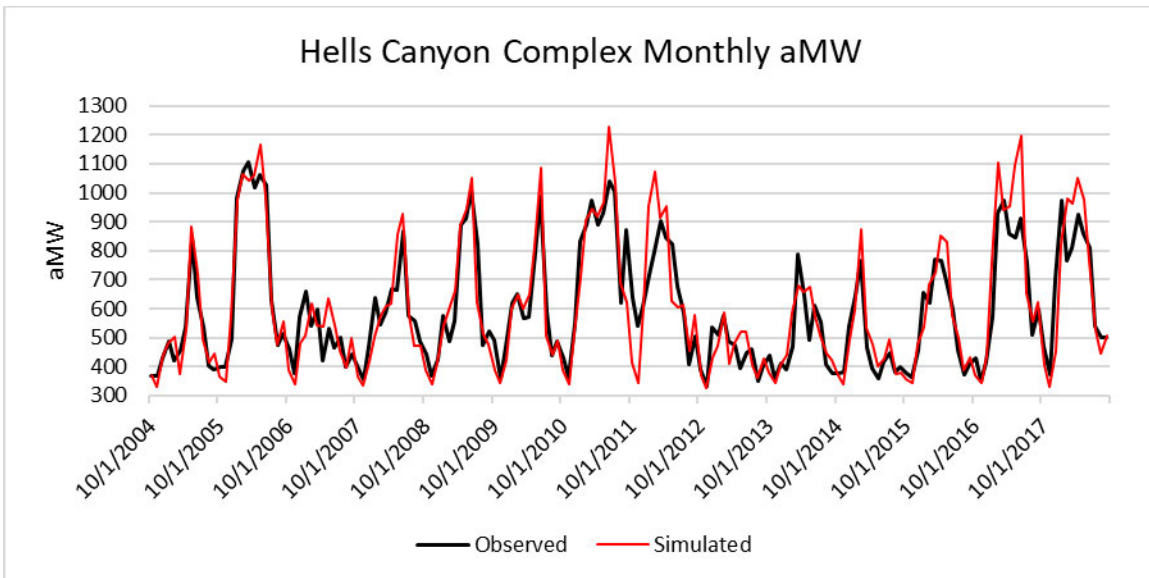


Figure 2: Observed vs Simulated Monthly aMW - IPC Hydro



1 **Q. Were any additional changes made to the hydro modeling process for the 2024**
2 **APCU October Update?**

3 A. No additional changes were made to the hydro modeling process for this year's
4 October Update.

5 Other

6 **Q. What other AURORA inputs were modified from last year's October Update?**

7 A. The Company updated the maintenance rates, forced outage rates, heat rates, start
8 costs, and other operating constraints for its thermal plants to better align the
9 AURORA-dispatched generation with how the plants are typically operated. This is a
10 consistent practice for every APCU filing.

11 The Company also included forecast demand response in the 2024 APCU
12 model. Demand response was modeled according to the parameters of its three
13 programs: A/C Cool Credit, Flex Peak Program, and Irrigation Peak Rewards. Based
14 on actual 2022 participation, Idaho Power assumed the programs would provide a total
15 of 320 MW of peak capacity from June 1 – September 15. No expenses associated
16 with demand response were included in this filing.

17 Lastly, the Company included annualized forecast generation from its Oregon
18 Community Solar Program, which is scheduled to come online by the end of 2023. No
19 expenses associated with this program were included in this filing.

20 **Q. Please describe any modifications made to the total NPSE calculation in this**
21 **year's October Update.**

22 A. Idaho Power made three modifications to the total NPSE calculation in this year's
23 October Update. The first is the modification for Black Mesa Solar, which was
24 introduced in last year's October Update. The second is a modification related to a
25 new special contract with Lamb Weston, Inc. ("Lamb Weston"). The final modification
26 is the inclusion of revenue received from third-party transmission wheeling losses.

1 **Q. Please explain the modification related to Black Mesa Solar.**

2 A. The Black Mesa Solar PPA was negotiated in conjunction with a new special contract
3 with Micron Technology, Inc. ("Micron"). Micron's Special Contract states that Idaho
4 Power will procure renewable resources to assist Micron in meeting a portion of its
5 annual energy requirements with energy generated by those resources. While the
6 renewable resource, Black Mesa Solar in this case, will not serve Micron directly, and
7 rather will be connected to the Company's system, Micron will pay for all of the output.
8 Because Micron will be paying for 100 percent of the Black Mesa Solar PPA, the cost
9 of the PPA is excluded from the Company's calculation of NPSE. In addition, the
10 corresponding portion of forecast sales from Micron met by the Black Mesa resource
11 are removed from the total customer level sales for the test year. As a result, expenses
12 associated with Black Mesa Solar have been excluded from the final NPSE and related
13 Micron sales have been removed from the per-unit cost calculation. Line 20 of
14 Exhibit 105 illustrates the total forecast generation from Black Mesa Solar of
15 0.099 million MWh and Line 29 shows the total expense of \$0.

16 **Q. Please explain the modification related to Lamb Weston.**

17 A. In Order No. 35929, the Idaho Public Utilities Commission approved a new special
18 contract with Lamb Weston for its Idaho operations.⁹ Lamb Weston's special contract
19 consists of a two-block pricing structure that includes an embedded-cost pricing block,
20 Block 1, and marginal energy cost pricing block, Block 2. Block 2 consists of electricity
21 consumed beyond 20 MW. According to their special contract, revenues from Block 2
22 energy sales should be treated as a surplus sale in NPSE calculations. As a result,
23 revenues associated with Lamb Weston's forecast Block 2 energy sales have been
24

25 _____
26 *9 In the matter of Idaho Power's Application for Approval of Special Contract and Tariff Schedule 34 to Provide
Electric Service to Lamb Weston, Inc., Docket No. IPC-E-23-18. Order No. 35929 (September 21, 2023)*

1 included as an offset to NPSE and the associated MWh have been removed from the
2 per-unit cost calculation.

3 Line 52 of Exhibit 105 contains the forecast Block 2 revenue from Lamb
4 Weston, referred to as Lamb Weston Surplus Sales, of \$4.4 million. Line 58 contains
5 the total forecast Block 2 energy sales. Line 59 contains the total customer level sales,
6 net of Black Mesa Solar's generation and Lamb Weston Block 2 energy sales, which
7 is used in the final per-unit cost calculation on Line 61.

8 **Q. Please explain the modification related to third-party transmission wheeling
9 losses.**

10 A. As discussed earlier in my testimony, the load forecast used in this year's October
11 Update includes an additional 36 MW in each hour to serve third-party transmission
12 losses. As a result, Idaho Power has also included the revenue associated with this
13 additional generation as an offset to total NPSE. This was calculated by multiplying
14 Idaho Power's average hourly marginal resource price, as calculated by AURORA, by
15 the 36 MW. Line 51 of Exhibit 105 contains the total revenue associated with third-
16 party transmission losses.

17 Modeling Results

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

20 A. Yes. Exhibit 101 shows the results of the AURORA modeling determination of
21 normalized NPSE for the April 2024 through March 2025 test year. It presents the
22 summary of results containing average variable power supply generation output and
23 expenses based on 37 historical water conditions.

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

25 A. Hydro generation supplies 8.22 million MWh, approximately 48 percent (8.22 million
26 MWh / 17.26 million MWh = 48 percent) of the generation mix. Thermal generation

1 supplies 5.12 million MWh (Bridger 1.62, Valmy 0.47, Bridger Gas 0.64, Langley Gulch
2 1.83, Danskin 0.34, Bennett Mountain 0.23), approximately 30 percent (5.12 million
3 MWh / 17.26 million MWh = 30 percent) of the generation mix. Purchases of power
4 are made up of short-term and longer-term market purchases, PPAs, and PURPA.
5 PURPA purchases reflect normalized and annualized generation levels and account
6 for 3.11 million MWh. The generation volumes and costs associated with PURPA
7 purchases are not shown on Exhibit 101; however, when combined with market
8 purchases of 1.25 million MWh and PPAs of 1.68 million MWh, total purchases amount
9 to 6.03 million MWh (3.11 million MWh + 1.25 million MWh + 1.68 million MWh =
10 6.03 million MWh) or approximately 35 percent of the generation mix. Of the
11 19.33 million MWh generated by the system, 17.26 million MWh are used for system
12 loads while 2.06 million MWh are sold as surplus sales.¹⁰

13 **Base Net Power Supply Expenses**

14 **Q. How are the Base Net Power Supply Expenses to be calculated for the October**
15 **Update portion of the APCU according to the settlement stipulation approved in**
16 **Order No. 08-238?**

17 **A.** Per Order No. 08-238, the output of the AURORA model will be used to determine net
18 power supply average dispatch cost for normal loads and average stream flow
19 conditions, and the wholesale electric prices for purchased power and surplus sales
20 determined by the AURORA model will be replaced with an average forward electric
21 price curve.¹¹

22
23
24
25 ¹⁰ Totals may not sum due to rounding.

26 ¹¹ *Id* at 2, p. 3.

1 **Q. Please describe the re-pricing methodology mentioned above.**

2 A. The Company is required to re-price the AURORA-generated volumes of purchased
3 power and surplus sales with a forward-based price curve using the Mid-C hub. This
4 methodology prescribes the use of a one-year average of the daily Mid-C forward price
5 curves calculated from the previous 12 months of daily Mid-C heavy load (“HL”) and
6 Mid-C light load (“LL”) forward price curves for the period starting in the April
7 immediately following the current April through March test period. Forward prices are
8 then adjusted for inflation back one year using the most recent Producer Price Index
9 for Electric Power.

10 The re-pricing of market prices in the 2024 October Update is based upon the
11 daily forward price curves for April 2025 through March 2026 as shown in Exhibit 102,
12 which were then discounted for inflation back to April 2024 through March 2025
13 according to the quarterly inflation indices provided in Exhibit 103.

14 **Q. Did Idaho Power make any adjustments to the re-pricing methodology approved**
15 **in Order No. 08-238?**

16 A. Yes. In Docket No. UE 384, Idaho Power proposed two adjustments to the re-pricing
17 methodology approved in Order No. 08-238, which were subsequently approved in
18 Order No. 21-165.¹² The Company incorporated both these adjustments to the re-
19 pricing methodology used in this case. The first adjustment eliminated the fixed
20 percentages, as prescribed in Order No. 08-238, used to adjust HL and LL forward
21 prices depending on whether the applicable market energy was purchased or sold.
22 Removing these fixed percentage adjustments results in market energy being re-
23 priced at the established HL or LL forward market prices. The second adjustment
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26 ¹² *In the Matter of Idaho Power Company's 2023 Annual Power Cost Update*, Docket No. UE 384.
Order No. 21-165 (May 27, 2023).

1 relates to the percentages used to determine the portion of AURORA-generated
2 purchased power and surplus sales that occur in HL and LL hours. Historically, these
3 percentages relied on the average of actual purchased power and surplus sales
4 volumes in HL and LL hours for the years 2003-2007. In docket UE 384, Idaho Power
5 updated the percentages based on an average of actual purchased power and surplus
6 sales volumes in HL and LL hours for the years 2016 – 2020. The Company updated
7 these percentages in this year’s October update to incorporate data from 2018 – 2022.

8 **Q. What is the monthly average forward price that is used for the re-pricing of**
9 **purchased power and surplus sales volumes?**

10 A. Exhibit 104 shows the monthly prices that are used for the re-pricing of purchased
11 power and surplus sales volumes for the 2024 October Update. The prices range from
12 a low of \$33.29 per MWh to a high of \$166.20 per MWh.

13 **Q. How does the re-pricing of purchased power and surplus sales, using a normal**
14 **forward price curve, change purchased power expenses and surplus sales**
15 **revenues as modeled by AURORA?**

16 A. Lines 33 and 59 of Exhibit 101 show the purchased power expenses and surplus sales
17 revenues, respectively, as determined by the AURORA modeling process. Lines 24
18 and 50 of Exhibit 105 show the same normalized generation dispatch with purchased
19 power and surplus sales re-priced using the normalized forward price curve shown in
20 Exhibit 104. A comparison of Exhibit 101 and Exhibit 105 demonstrates the changes
21 due to re-pricing. Purchased power expenses increased by \$66.6 million, moving from
22 \$50.7 million to \$117.3 million. Surplus sales revenues increased by \$57.3 million,
23 moving from \$106.6 million to \$164.0 million. In this case, the NPSE resulting from the
24 re-pricing methodology shown in Exhibit 105 is an increase in NPSE of \$9.3 million as
25 compared to the AURORA-generated expense shown on Exhibit 101. The differences
26

1 for the re-pricing of purchased power of \$66.6 million and surplus sales of \$57.3 million
2 are shown in Exhibit 108, Column J.

3 Energy Imbalance Market (“EIM”) Benefits and Costs

4 **Q. Has the Company adjusted the NPSE amounts included in the 2024 October**
5 **Update to reflect Idaho Power’s participation in the Western EIM?**

6 A. Yes. The NPSE requested for approval in the 2024 October Update includes both the
7 incremental benefits and costs associated with Idaho Power’s participation in the
8 Western EIM. This treatment is consistent with the methodology approved by the
9 Commission in Idaho Power’s 2018 - 2023 APCU dockets.¹³

10 **Q. What level of EIM benefits is Idaho Power proposing to include in the 2024**
11 **October Update?**

12 A. Idaho Power is proposing to include \$48.4 million in system EIM benefits as an offset
13 to NPSE in the 2024 October Update. On an Oregon allocated basis, the EIM benefits
14 to be included in the 2024 October Update are approximately \$2.1 million.

15 **Q. How does this compare to the level of EIM benefits included in last year’s**
16 **October Update?**

17 A. The settled 2023 October Update system EIM benefit was \$34.7 million, or
18 \$1.55 million on an Oregon allocated basis.

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

20 A. CAISO uses a counterfactual methodology in which dispatch for an EIM Balancing
21 Authority Area (“BAA”) mimics market operations without importing or exporting
22 through EIM transfers. The counterfactual dispatch moves units inside the BAA to
23 meet real-time imbalance based on economic merit order. CAISO’s quantification of
24

25 _____
26 ¹³ Docket Nos. UE 350, UE 350, UE 366, UE 384, and UE 414. Order Nos., 18-170, 19-189, 20-164, 21-165, and 23-184.

1 total estimated EIM benefits is the cost savings of the EIM dispatch compared to the
2 counterfactual without EIM dispatch. In order to determine both EIM dispatch costs
3 and counterfactual costs, CAISO relies upon bid prices submitted by EIM entities.

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

6 A. One of the major assumptions CAISO makes in its benefits methodology, due to lack
7 of other data, is that the bids submitted for each participating resource reflect the true
8 dispatch costs, or the economic value, of those resources. For most resource types,
9 this assumption may be reasonable; however, this assumption is not accurate for
10 hydro resources.

11 Idaho Power bids hydro resources based on an operational need rather than
12 actual dispatch cost. Additionally, Idaho Power utilizes various pricing tiers for its hydro
13 resources to protect the water from overuse in the market and to adhere to regulated
14 water management requirements.¹⁴ The pricing tiers that Idaho Power uses are based
15 upon certain operational parameters and can result in high bid prices when it is
16 necessary to cease or limit water flows for a particular hydro resource's market
17 participation. When Idaho Power operators move water into the higher tiers, which
18 have a higher bid price, it is a response to operational needs and does not reflect
19 market benefits.

20
21 Without adjusting for these operating scenarios, CAISO's EIM benefit
22 methodology incorrectly reflects the bid tier price as the economic value of hydro in
23 the determination of both counterfactual costs and EIM dispatch costs, thereby
24 overstating the resulting benefits. In order for the EIM benefit calculation to properly
25

26 ¹⁴ Requirements may include flood control obligations, fish flow obligations, etc.

1 serve as an adjustment to modeled NPSE, Idaho Power adjusted the CAISO
2 methodology as it pertains to the hydro pricing cost structure.

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

5 A. To reflect the correct economic value of the hydro dispatches in the EIM benefit
6 calculation, Idaho Power made a two-part adjustment to the hydro cost structure. First,
7 all hydro dispatch costs are held constant by applying a zero-cost. This satisfies a
8 correction to CAISO's EIM counterfactual costs as there shouldn't be any costs
9 associated with Idaho Power's dispatching up and down of its hydro resources to meet
10 its load imbalances.

11
12 Holding the dispatch costs constant by applying a zero-cost also satisfies a
13 correction to the EIM dispatch costs. The EIM is not a capacity market. Therefore, in
14 a hydro system with limited ability to store water long-term, EIM imports (or the
15 dispatching down and storage of the water) will have matching exports over a given
16 time period (that hydrogeneration will be exported soon thereafter). When EIM hydro
17 imports match exports over a measured period, in the case of Idaho Power's analysis
18 an hourly basis,¹⁵ dispatch costs should be held constant by replacing all tier prices
19 with a zero cost. In this scenario, the actual benefit is the difference between the EIM
20 import and export price. If the EIM dispatch cost is not held constant over the
21 measured period, it results in an inaccurate benefit.

22 However, when hydro imports do not equal exports, it is necessary to value, or
23 assign a cost to, the net import / exports to the market. This is the second part of the
24

25 ¹⁵ The adjustments to the hydro pricing cost structure for the EIM benefit calculation are performed on an hourly
26 basis at the recommendation of OPUC Staff. *In the Matter of Idaho Power Company's 2020 Annual Power Cost Update*, Docket UE 366, Idaho Power/300, Blackwell/17-18 (March 24, 2020).

1 adjustment Idaho Power made to the hydro pricing cost structure as it pertains to the
2 EIM benefit calculation.

3 **Q. Why is it necessary to value net imports and exports related to the EIM?**

4 A. When imports exceed exports during the measured period, using a zero-cost value
5 will underestimate benefits because it does not properly account for the value of
6 imported energy that serves load (rather than hydro) and provides a benefit to the
7 Company's customers. Conversely, when exports exceed imports during the
8 measured period, the zero-cost value will inflate benefits because there aren't any
9 costs assigned to the hydrogeneration that was moved into the market. In either
10 scenario, the net imports / exports for the hydro resources will show a benefit at the
11 EIM Locational Marginal Price ("LMP") because there are no costs associated with the
12 hydro dispatches. As a result, it is necessary to make a second adjustment to the EIM
13 benefit calculation to properly account for the hydro cost when imports do not equal
14 exports for the measured period.

15 **Q. Please explain the methodology used by the Company to value EIM net imports
16 and exports of hydro-related energy.**

17 A. Idaho Power adjusted the EIM benefits by replacing the zero-priced dispatch cost with
18 the Powerdex Mid-C hourly market electricity price for all hours that the Company was
19 a net importer or net exporter. Applying a market price to the net hydro import / export
20 position allows the Company to properly account for the cost savings associated with
21 imported energy that served load rather than hydro, or the costs associated with hydro
22 energy exported to the EIM. The market prices were multiplied by the net import/export
23 position and the adjusted savings/costs were applied to the zero-cost benefit method
24 to accurately calculate EIM benefits for hydro resources.

25
26

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

3 A. Yes. Exhibit 106 demonstrates Idaho Power's adjustments to the CAISO EIM benefit
4 methodology as it pertains to the hydro pricing cost structure for the full 12-month
5 period. Column A of Exhibit 106/1 includes CAISO's reported benefits for Idaho Power
6 for September 2022 – August 2023 of \$74.6 million. Column B illustrates Idaho
7 Power's application of a zero-cost for all hydro tier prices when EIM imports equal
8 exports on an hourly basis. This adjustment resulted in an EIM benefit of \$43.1 million,
9 a \$31.5 million reduction from CAISO's stated EIM benefits for Idaho Power.

10 Column C of Exhibit 106/1 demonstrates the adjustment to the hourly net
11 import / export position for the hydro resources. As discussed previously, Idaho Power
12 assigned a value to the net import / export position for each hour based on the
13 Powerdex Mid-C market electricity price. This adjustment resulted in a \$5.3 million
14 increase to Idaho Power's EIM benefit estimate.

15 **Q. Please summarize the final estimate of EIM benefits to be included in the 2024**
16 **APCU.**

17 A. The Company's EIM benefits forecast is based on the CAISO's EIM benefits reports,
18 with necessary adjustments for hydro pricing as described in this testimony. As
19 detailed in Exhibit 106, the Company's total estimated benefit for September 2022
20 through August 2023 is \$48.4 million, or \$2.1 million on an Oregon jurisdictional basis.
21 The Company has included the estimate of EIM benefits as an offset to forecast NPSE
22 for the October Update as shown in Exhibit 105.

23 **Q. Please describe the incremental costs of Western EIM participation.**

24 A. As stated previously, by participating in the Western EIM, the Company achieves
25 NPSE savings, which benefit customers; however, to achieve such benefits, Idaho
26 Power has incurred, and will continue to incur, incremental costs to participate in the

1 Western EIM, including software and metering investments and annual, ongoing
2 operations and maintenance (“O&M”) expenses. Consistent with prior APCU dockets,
3 the Company has included EIM-related costs in the 2024 APCU. The EIM-related
4 costs included in the 2024 October Update consist of the annual return on net rate
5 base from the capital investment required to participate in the Western EIM,
6 depreciation expense, and ongoing O&M expenses. On an Oregon allocated basis,
7 the revenue requirement associated with EIM costs to be included in the 2024 October
8 Update is \$124,718, as shown in Exhibit No. 107.

9 Per-Unit Cost Calculation and NPSE Discussion

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

12 A. Exhibit 105 shows total system NPSE of \$483.7 million and normalized annual sales
13 at the customer level for the April 2024 through March 2025 test year, net of Black
14 Mesa Solar’s generation and Lamb Weston Surplus Sales, of 15,792,635 MWh,
15 resulting in a per-unit cost for the 2024 October Update of \$30.63 per MWh
16 (\$483.7 million / 15.792 million MWh = \$30.63 per MWh) to become effective on
17 June 1, 2024.

18 **Q. How does the 2024 October Update per-unit cost of \$30.63 per MWh compare to**
19 **the 2023 October Update per-unit cost?**

20 A. The 2023 October Update per-unit cost, which became effective June 1, 2023, was
21 \$30.8 per MWh based upon a determination of total NPSE of \$481.3 million

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

24 A. Yes. Exhibit 108 compares the AURORA-developed results, the re-pricing of
25 purchased power and surplus sales, and the differences between the 2023 October
26 Update and the 2024 October Update. Column H of Exhibit 108 shows the following:

1 (1) An increase in coal expenses of \$2.5 million associated with a decrease of
2 0.37 million MWh in generation, (2) an increase in natural gas expenses of
3 \$110.1 million associated with an increase of 1.9 million MWh in generation, (3) a
4 decrease in market purchased power expenses of \$16.8 million associated with a
5 decrease of 0.95 million MWh, (4) an increase in PPA expenses of \$24.7 million
6 associated with an increase of 0.69 million MWh, (5) an increase in PURPA expenses
7 of \$10.1 million associated with a decrease of 0.07 million MWh, and finally, (6) an
8 increase in surplus sales revenue of \$114.4 million associated with an increase of
9 0.97 million MWh.

10 **Q. Can you elaborate more on the changes in generation from the 2023 October**
11 **Update to the 2024 October Update?**

12 A. Yes. To illustrate the changes in generation, Columns D (2023) and F (2024) of Exhibit
13 108 calculate the percentage of generation compared to total system load. For
14 example, Column F, line 1, shows that hydro provided 48 percent of the generation to
15 meet the total system load of 17,264,409 MWh ($8,224,002 / 17,264,409 = 48$ percent)
16 compared to 49 percent in the 2023 October Update. Coal generation decreased from
17 14 percent to 12 percent, natural gas generation increased from 7 percent to
18 18 percent, market purchased power decreased from 13 percent to 7 percent, PPA
19 generation increased from 6 percent to 10 percent, PURPA generation decreased
20 from 19 percent to 18 percent, and lastly, surplus sales increased from 6 percent to
21 12 percent. This comparison between resource type and total system load shows that
22 reduced coal generation and market purchases is being met with increased natural
23 gas and PPA generation. In addition, the increase in natural gas and PPA generation
24 resulted in increased opportunity to make economic off-system sales.

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1 **Q. Are the changes in expenses among resource types consistent with the changes**
2 **in output?**

3 A. Yes. The changes in expenses among resource types are relatively consistent with
4 the changes in output, especially when considering the changes in the per-unit cost of
5 the various resources. The changes in expenses for each resource type are also
6 shown in Columns D (2023) and F (2024) of Exhibit 108 as follows: Coal expense
7 remained unchanged at 17 percent of total NPSE, natural gas expense increased from
8 11 percent to 34 percent, market purchased power expense decreased from
9 28 percent to 24 percent, PPA expense increased from 12 percent to 17 percent,
10 PURPA expense increased from 50 percent to 52 percent, and surplus sales revenue
11 increased from 10 percent to 34 percent. Exhibit 108 demonstrates that the majority
12 of movement in NPSE is related to the increase in natural gas generation and increase
13 in economic surplus sales.

14 **Q. What can be concluded from the information presented in Exhibit 108?**

15 A. The information shown in Exhibit 108 confirms that the 15 percent decrease in coal
16 generation combined with the 43 percent decrease in market purchases are being met
17 with a 170 percent increase in natural gas generation and an 88 percent increase in
18 surplus sales from last year's October Update.

19 **Q. Did the Company comply with the methodology in Order No. 08-238 when it**
20 **performed its analysis to determine the NPSE for the 2024 October Update?**

21 A. Yes. The Company has complied with the methodology detailed in Order No. 08-238
22 for calculating this year's October Update.

23 *Jurisdictional Allocation of NPSE*

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

25 A. The Oregon jurisdictional share of NPSE is calculated by multiplying the system NPSE
26 total per-unit cost of \$30.63 per MWh by the forecasted Oregon jurisdictional loss-

1 adjusted normalized sales for the April 2024 through March 2025 test period of
2 681,006.975 MWh, resulting in an Oregon jurisdictional share of NPSE of \$20.86
3 million ($\$30.63 \times 681,006.975 \text{ MWh} = \20.86 million), as shown on Line 1 of
4 Exhibit 109.

5 Quantification and Discussion of the APCU Revenue Requirement

6 **Q. Based on the determination of the Oregon jurisdictional share of NPSE, what is**
7 **the APCU revenue requirement for the 2024 October Update?**

8 A. As shown on Line 3 of Exhibit 109, the APCU revenue requirement is \$20.98 million.
9 The APCU revenue requirement is calculated by adding the 2024 October Update
10 Oregon jurisdictional share of NPSE of \$20.86 million, Line 1, to the Oregon allocated
11 EIM costs of \$124,718 Line 2.

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

14 A. Exhibit 109 also reveals the revenue impact resulting from this year's October Update.
15 As shown on Line 12, base NPSE recovery under current approved APCU rates is
16 \$21.09 million, whereas the proposed 2024 APCU October Update revenue
17 requirement is \$20.98 million, as shown on Line 3. The comparison of this year's
18 October Update to current approved revenue indicates a decrease in Oregon
19 customer rates of \$101,556.

20 Rate Implementation

21 **Q. What method of allocation did the Company use to spread the APCU revenue**
22 **requirement associated with the 2024 October Update to the various customer**
23 **classes?**

24 A. The Company allocated the \$20.98 million APCU revenue requirement associated
25 with the 2024 October Update using the revenue spread methodology agreed upon in
26

1 the settlement stipulation approved by Order No. 18-170.¹⁶ Order No. 18-170
2 established a revenue spread methodology whereby the total APCU revenue
3 requirement is allocated to individual customer classes on the basis of normalized
4 jurisdictional forecasted sales at the generation level for the test period. It should also
5 be noted that the agreed upon revenue spread methodology included a provision that
6 any rate increases resulting from application of this new methodology as applied to a
7 customer class would be capped at 3 percent above the overall average rate increase
8 on a percentage of total revenue basis. This cap was implemented to recognize that
9 the movement to the new methodology could result in relatively large increases for
10 individual classes within a single year. The cap is not applicable for the 2024 APCU.

11 **Q. Have you provided an exhibit with the final proposed revenue spread?**

12 A. Yes. The final proposed revenue spread resulting from the application of the stipulated
13 methodology is provided in Exhibit 109.

14 **Q. Have you prepared an exhibit showing the summary of the revenue impact
15 resulting from the October Update proposed by the Company?**

16 A. Yes. Exhibit 110 provides a summary of the revenue change resulting from this year's
17 October Update as compared to current revenue.

18 **Q. Does the Company intend to provide supporting workpapers for the 2024
19 October Update to Staff and CUB?**

20 A. Yes. Idaho Power will provide its supporting workpapers to Staff and CUB as part of
21 the 2024 APCU filing. The Company intends to provide these workpapers within five
22 business days of filing the 2024 APCU.

23

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26 ¹⁶ *In the Matter of Idaho Power Company's 2018 Annual Power Cost Update*, Docket No. UE 333.
Order No. 18-170 (May 21, 2018).

1 **Q. Does this conclude your testimony?**

2 **A.** Yes, it does.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 101

Idaho Power Company's AURORA Modeled
Determination Of Normalized Power Supply
Expenses for April 1, 2024 – March 31, 2025

October 31, 2023

Idaho Power/101
Brady/1

PCO NORMALIZED POWER SUPPLY EXPENSES FOR APR L 1, 2024 -- MARCH 31, 2025 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2024 October Update
Variable Coal Handling Costs Modeled Using UE 301 & UE 314 Settlement Methodologies
AVERAGE

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Annual
1	Hydroelectric Generation (MWh)	834,153.8	870,903.5	828,403.4	733,139.6	604,718.6	565,857.1	461,336.2	415,272.5	577,363.9	772,382.1	757,438.8	803,032.1	8,224,001.6
	Bridger													
2	Energy (MWh)	78,676.6	43,194.7	29,707.1	135,250.7	156,657.2	119,000.9	129,756.1	223,255.2	247,453.9	192,735.3	214,106.2	45,287.0	1,615,080.9
3	AURORA Modeled Expense (\$ x 1000)	\$ 3,130.3	\$ 2,026.6	\$ 1,577.7	\$ 4,945.0	\$ 5,623.6	\$ 4,408.6	\$ 4,770.7	\$ 7,713.9	\$ 8,502.5	\$ 7,121.3	\$ 7,767.6	\$ 2,146.9	\$ 59,734.7
4	AURORA Modeled Handling Expense (\$ x 1000)	\$ (29.9)	\$ (16.4)	\$ (11.3)	\$ (51.4)	\$ (59.5)	\$ (45.2)	\$ (49.3)	\$ (84.8)	\$ (94.0)	\$ (73.2)	\$ (81.4)	\$ (17.2)	\$ (613.7)
5	AURORA Expense less Modeled Handling Expense (\$ x 1000)	\$ 3,160.2	\$ 2,043.0	\$ 1,588.9	\$ 4,996.4	\$ 5,683.1	\$ 4,453.8	\$ 4,820.0	\$ 7,798.8	\$ 8,596.6	\$ 7,194.5	\$ 7,848.9	\$ 2,164.1	\$ 60,348.4
6	IPC Share of OHAG Expense (\$ x 1000)	\$ (238.7)	\$ (238.7)	\$ (238.7)	\$ (238.7)	\$ (238.7)	\$ (238.7)	\$ (238.7)	\$ (238.7)	\$ (238.7)	\$ (238.7)	\$ (238.7)	\$ (238.7)	\$ (2,863.8)
7	Total Expense (\$ x 1000)	\$ 2,921.5	\$ 1,804.3	\$ 1,350.3	\$ 4,757.8	\$ 5,444.5	\$ 4,215.2	\$ 4,581.4	\$ 7,560.1	\$ 8,357.9	\$ 6,955.9	\$ 7,610.3	\$ 1,925.5	\$ 57,484.5
	Valmy													
8	Energy (MWh)	20,829.0	27,633.7	35,768.1	43,591.7	43,201.8	37,069.6	29,297.4	41,337.1	58,827.2	46,060.4	47,011.8	37,385.7	468,013.5
9	AURORA Modeled Expense (\$ x 1000)	\$ 1,149.2	\$ 1,521.4	\$ 1,935.8	\$ 2,324.3	\$ 2,301.8	\$ 1,991.9	\$ 1,600.7	\$ 2,186.1	\$ 3,061.0	\$ 2,504.5	\$ 2,543.2	\$ 2,066.9	\$ 25,186.8
10	AURORA Modeled Handling Expense (\$ x 1000)	\$ 46.9	\$ 62.2	\$ 80.5	\$ 98.1	\$ 97.2	\$ 83.4	\$ 65.9	\$ 93.0	\$ 132.4	\$ 103.6	\$ 105.8	\$ 84.1	\$ 1,053.0
11	AURORA Expense less Modeled Handling Expense (\$ x 1000)	\$ 1,102.3	\$ 1,459.2	\$ 1,855.4	\$ 2,226.2	\$ 2,204.6	\$ 1,908.5	\$ 1,534.7	\$ 2,093.1	\$ 2,928.6	\$ 2,400.8	\$ 2,437.4	\$ 1,982.8	\$ 24,133.8
12	IPC Share of OHAG Expense (\$ x 1000)	\$ 257.9	\$ 257.9	\$ 257.9	\$ 257.9	\$ 257.9	\$ 257.9	\$ 257.9	\$ 257.9	\$ 257.9	\$ 257.9	\$ 257.9	\$ 257.9	\$ 3,095.2
13	Usage Charges Paid to IPC (\$ x 1000)	\$ (5.9)	\$ (5.9)	\$ (5.9)	\$ (5.9)	\$ (5.9)	\$ (5.9)	\$ (5.9)	\$ (5.9)	\$ (5.9)	\$ (5.9)	\$ (5.9)	\$ (5.9)	\$ (71.1)
14	Total Expense (\$ x 1000)	\$ 1,354.3	\$ 1,711.2	\$ 2,107.4	\$ 2,478.3	\$ 2,456.6	\$ 2,160.5	\$ 1,786.8	\$ 2,345.1	\$ 3,180.6	\$ 2,652.8	\$ 2,689.4	\$ 2,234.8	\$ 27,157.9
	Bridger Gas													
15	Energy (MWh)	17,734.0	53,924.4	74,312.9	83,875.8	86,529.9	72,290.8	67,114.9	51,169.1	25,689.9	22,380.4	21,498.3	59,865.8	636,386.2
16	Expense (\$ x 1000)	\$ 1,233.3	\$ 2,766.0	\$ 3,594.0	\$ 4,642.2	\$ 4,834.0	\$ 4,054.2	\$ 3,725.9	\$ 3,957.2	\$ 3,783.4	\$ 3,745.0	\$ 3,388.4	\$ 4,318.9	\$ 44,042.4
	Langley Gulch													
17	Energy (MWh)	143,490.4	183,219.7	195,458.6	212,035.0	216,097.2	198,344.8	201,824.3	115,633.8	40,761.1	61,929.3	108,116.9	155,133.1	1,832,044.2
18	Expense (\$ x 1000)	\$ 4,488.1	\$ 4,672.8	\$ 5,190.3	\$ 7,067.7	\$ 7,482.0	\$ 6,583.0	\$ 6,485.9	\$ 6,849.9	\$ 3,017.3	\$ 4,835.7	\$ 7,935.9	\$ 7,864.0	\$ 72,472.5
	Danskin													
19	Energy (MWh)	36,386.5	30,593.5	29,181.2	35,384.3	34,753.5	27,858.7	28,674.7	21,054.0	22,397.2	13,644.7	17,969.1	38,810.9	336,708.1
20	Expense (\$ x 1000)	\$ 1,614.3	\$ 1,093.5	\$ 1,112.6	\$ 1,802.0	\$ 1,853.7	\$ 1,374.0	\$ 1,363.7	\$ 1,963.6	\$ 2,715.8	\$ 1,652.3	\$ 2,049.1	\$ 3,030.7	\$ 21,625.5
	Bennett Mountain													
21	Energy (MWh)	21,995.8	20,172.0	19,348.7	22,762.7	22,373.6	18,633.5	19,112.7	15,049.3	17,764.1	13,050.4	16,512.5	24,795.6	231,570.7
22	Expense (\$ x 1000)	\$ 955.2	\$ 701.3	\$ 718.3	\$ 1,126.0	\$ 1,159.2	\$ 897.1	\$ 884.6	\$ 1,351.6	\$ 2,086.6	\$ 1,545.3	\$ 1,858.0	\$ 1,892.2	\$ 15,175.5
23	Fixed Capacity Charge - Gas Transportation (\$ x 1000)	835.84	848.99	835.84	853.73	858.47	831.10	858.47	835.84	853.73	858.47	785.84	858.47	10,114.8
	Purchased Power (Excluding PURPA)													
24	Market Energy (MWh)	40,572.5	39,307.0	119,908.9	238,528.6	192,766.3	54,908.4	33,862.4	102,277.9	191,405.0	122,397.4	43,426.7	68,634.6	1,247,995.5
25	Elkhorn Wind Energy (MWh)	26,142.4	26,302.5	24,515.6	28,797.5	25,165.1	19,376.0	21,070.2	26,306.7	30,330.8	33,465.9	23,489.1	25,537.4	310,499.1
26	Jackpot Solar Energy (MWh)	7,871.4	14,384.5	20,427.1	25,685.1	29,177.1	33,777.8	33,025.7	27,862.3	23,505.0	18,009.1	9,518.0	7,147.6	250,390.7
27	Neal Hot Springs Energy (MWh)	8,524.8	9,916.3	12,648.3	16,278.3	19,120.0	19,165.9	19,441.7	18,897.0	18,338.7	17,194.5	12,566.6	11,833.6	183,926.0
28	Raft River Geothermal Energy (MWh)	6,669.5	6,986.7	6,984.7	7,674.2	8,195.5	8,238.1	8,560.0	8,468.1	8,541.8	6,952.7	6,689.0	6,858.5	90,819.0
29	Black Mesa Solar Energy (MWh)	3,096.9	5,659.5	8,036.9	10,105.5	11,479.4	13,289.5	12,993.6	10,962.1	9,247.8	7,085.5	3,744.8	2,812.2	98,513.7
30	Franklin Solar Energy (MWh)	23,798.4	28,813.4	32,016.5	33,016.7	29,568.5	25,740.0	19,727.6	11,995.9	10,810.5	12,855.5	15,220.6	21,353.9	264,917.5
31	Pleasant Valley Solar Energy (MWh)	15,823.3	25,932.9	37,984.6	51,014.0	56,229.0	62,369.8	64,005.9	54,817.6	46,942.6	33,234.4	15,795.4	14,145.9	478,295.3
32	Total Energy Excl. PURPA (MWh)	132,499.2	157,302.8	262,522.5	411,100.4	371,700.9	236,865.5	212,687.2	261,587.5	339,122.2	251,195.2	130,450.1	158,323.6	2,925,356.9
	Market Expense (\$ x 1000)													
33	Market Expense (\$ x 1000)	1,060.8	879.8	4,126.2	9,025.6	7,380.1	1,932.3	1,088.0	4,055.9	10,597.2	5,815.9	2,140.1	2,636.3	50,738.2
34	Elkhorn Wind Expense (\$ x 1000)	1,976.6	1,988.7	1,853.6	2,177.4	1,902.7	1,465.0	1,593.1	1,989.1	2,293.3	2,530.4	1,776.0	1,930.9	23,476.8
35	Jackpot Solar Expense (\$ x 1000)	174.4	318.6	452.5	568.9	646.3	748.2	731.5	617.2	520.6	398.9	210.8	158.3	5,546.1
36	Neal Hot Springs Expense (\$ x 1000)	1,069.9	1,244.6	1,587.5	2,043.1	2,399.8	2,405.5	2,440.1	2,371.8	2,301.7	2,158.1	1,485.2	1,485.2	23,084.6
37	Raft River Geothermal Expense (\$ x 1000)	470.9	493.3	493.2	541.9	578.7	581.7	604.4	597.9	603.1	490.9	472.3	484.3	6,412.7
38	Black Mesa Solar Expense (\$ x 1000)	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Franklin Solar Expense (\$ x 1000)	696.1	842.8	936.5	965.7	864.9	752.9	577.0	350.9	316.2	376.0	445.2	624.6	7,748.8
40	Pleasant Valley Solar Expense (\$ x 1000)	249.9	24.0	3,012.7	2,509.0	1,575.3	1,271.6	1,033.0	746.0	379.0	763.6	929.6	1,629.7	14,123.4
41	Total Expense Excl. PURPA (\$ x 1000)	5,698.7	5,791.9	12,462.1	17,831.6	15,347.6	9,157.2	8,067.2	10,728.7	17,011.3	12,533.8	7,551.3	8,949.3	131,130.7
	Storage													
42	Black Mesa Battery Energy (MWh)	(401.3)	(534.5)	(524.9)	(737.3)	(826.7)	(730.2)	(703.8)	(650.4)	(654.2)	(625.8)	(419.2)	(387.6)	(7,195.85)
43	80 MW Hemingway Battery Energy (MWh)	(2,583.0)	(2,215.7)	(1,735.6)	(1,750.6)	(1,749.2)	(1,856.9)	(2,537.8)	(2,458.9)	(2,465.7)	(2,794.3)	(2,546.5)	(2,868.5)	(27,562.75)
44	11 MW Grid Battery Energy (MWh)	(262.1)	(228.7)	(188.5)	(216.6)	(234.0)	(223.9)	(282.4)	(259.0)	(269.7)	(289.3)	(249.6)	(301.4)	(3,005.15)
45	Franklin Battery Energy (MWh)	(1,481.2)	(1,283.5)	(977.6)	(1,178.2)	(1,283.7)	(1,257.4)	(1,581.2)	(1,426.8)	(1,552.9)	(1,628.4)	(1,495.4)	(1,808.9)	(16,955.10)

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46	36 MW Hemingway Battery Energy (MWh)	(875.6)	(759.2)	(595.1)	(706.5)	(768.8)	(745.0)	(944.2)	(849.4)	(915.6)	(951.4)	(871.0)	(1,070.0)	(10,051.60)
47	Total Storage (MWh)	(5,603.2)	(5,021.7)	(4,021.7)	(4,589.0)	(4,862.4)	(4,813.4)	(6,049.5)	(5,644.5)	(5,858.1)	(6,289.1)	(5,581.6)	(6,436.4)	(64,770.45)
48	Black Mesa Battery Expense (\$ x 1000)	-	-	-	-	-	-	-	-	-	-	-	-	-
49	80 MW Grid Battery Expense (\$ x 1000)	-	-	-	-	-	-	-	-	-	-	-	-	-
50	11 MW Grid Battery Expense (\$ x 1000)	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Franklin Battery Expense (\$ x 1000)	-	-	-	-	-	-	-	-	-	-	-	-	-
52	36 MW Hemingway Battery Expense (\$ x 1000)	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Total Storage Expense (\$ x 1000)	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response													
54	Energy (MWh)	-	-	4,917.5	10,748.8	1,542.3	-	-	-	-	-	-	-	17,208.6
55	Cost(\$ X 1000)	-	-	-	-	-	-	-	-	-	-	-	-	-
	Oregon Solar													
56	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
57	Cost(\$ X 1000)	-	-	-	-	-	-	-	-	-	-	-	-	-
	Surplus Sales													
58	Energy (MWh)	326,032.7	288,002.0	162,568.9	35,193.5	53,124.5	184,167.7	228,570.6	109,921.8	64,142.7	137,165.0	223,416.5	252,572.4	2,064,878.1
59	Revenue (\$ x 1000)	\$ 11,166.2	\$ 9,071.0	\$ 5,649.1	\$ 1,834.0	\$ 3,017.8	\$ 9,238.7	\$ 9,978.9	\$ 5,623.4	\$ 3,692.9	\$ 6,440.8	\$ 12,204.3	\$ 11,478.1	\$ 89,395.0
60	Surplus Sales - Third Party Transmission Losses (\$ x 1000)	\$ 755.9	\$ 706.2	\$ 863.0	\$ 1,117.3	\$ 1,145.5	\$ 1,002.5	\$ 965.4	\$ 1,130.7	\$ 1,511.9	\$ 1,288.9	\$ 1,266.4	\$ 1,079.2	\$ 12,832.96
61	Lamb Weston Sales (\$ x 1000)	\$ 227.16	\$ 316.44	\$ 445.95	\$ 400.96	\$ 451.55	\$ 295.66	\$ 313.55	\$ 430.59	\$ 409.59	\$ 305.76	\$ 422.51	\$ 379.88	\$ 4,399.6
62	Net Power Supply Expenses (\$ x 1000)	\$ 6,951.9	\$ 9,296.4	\$ 20,412.7	\$ 37,207.0	\$ 34,821.3	\$ 18,735.5	\$ 16,496.2	\$ 28,407.4	\$ 35,392.3	\$ 26,743.9	\$ 19,974.9	\$ 18,136.7	\$ 272,576.3

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 102

Mid-Columbia Forward Price Curves Discounted for
Inflation

October 31, 2023

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
April 2020 - March 2021

Idaho Power/102
Brady/1

Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
10/4/2022	38.35	36.35	37.65	110.90	123.60	110.90	53.30	59.05	69.25	69.85	59.90	49.05
10/5/2022	38.75	36.70	38.00	112.00	124.85	112.00	53.85	59.65	69.95	70.65	60.60	49.60
10/6/2022	39.90	37.80	39.10	115.30	128.55	115.30	55.45	61.40	72.00	72.95	62.55	51.20
10/7/2022	44.00	41.70	43.15	116.20	129.55	116.20	55.90	61.90	72.55	73.55	63.05	51.60
10/10/2022	43.85	41.55	43.00	115.85	129.15	115.85	55.75	61.70	72.35	73.30	62.80	51.40
10/11/2022	44.90	42.55	44.05	118.80	132.45	118.80	57.15	63.25	74.20	75.60	64.75	53.00
10/12/2022	45.85	43.45	45.00	121.30	135.25	121.30	58.35	64.60	75.75	77.50	66.35	54.30
10/13/2022	45.60	43.25	44.75	120.70	134.55	120.70	58.05	64.30	75.35	77.90	66.70	54.60
10/14/2022	45.60	43.25	44.75	120.70	134.55	120.70	58.05	64.30	75.35	77.90	66.70	54.60
10/17/2022	45.90	43.55	45.05	121.50	135.40	121.50	58.40	64.70	75.85	79.05	67.70	55.40
10/18/2022	45.60	43.25	44.75	120.65	134.45	120.65	58.00	64.25	75.30	80.20	68.70	56.20
10/19/2022	45.20	42.90	44.35	118.25	131.80	118.25	56.85	63.00	73.80	78.55	67.30	55.05
10/20/2022	44.80	42.55	44.00	117.25	130.70	117.25	56.40	62.45	73.20	77.80	66.65	54.55
10/21/2022	43.25	41.10	42.50	113.25	126.25	113.25	54.45	60.30	70.70	74.80	64.05	52.45
10/24/2022	43.85	41.65	43.10	114.80	127.95	114.80	55.20	61.10	71.65	75.95	65.05	53.25
10/25/2022	46.20	43.85	45.40	120.90	134.75	120.90	58.15	64.35	75.45	80.20	68.70	56.25
10/26/2022	47.50	45.10	46.70	124.30	138.55	124.30	59.80	66.15	77.60	83.90	71.90	58.85
10/27/2022	48.65	46.20	47.85	127.35	141.95	127.35	61.25	67.75	79.50	87.05	74.60	61.05
10/28/2022	48.60	46.15	47.80	127.30	141.90	127.30	61.20	67.70	79.45	87.00	74.55	61.00
10/31/2022	48.95	46.50	48.15	130.40	145.35	130.40	62.70	69.35	81.40	89.10	76.35	62.45
11/1/2022	48.85	46.40	48.05	130.20	145.15	130.20	62.60	69.25	81.30	88.95	76.20	62.35
11/2/2022	48.95	46.50	48.15	131.90	147.05	131.90	63.45	70.15	82.35	90.10	77.15	63.15
11/3/2022	50.15	47.65	49.30	135.10	150.65	135.10	65.00	71.85	84.35	91.30	78.20	64.00
11/4/2022	50.85	48.30	50.00	137.00	152.80	137.00	65.90	72.85	85.55	93.35	79.95	65.45
11/7/2022	51.00	48.45	50.15	138.30	154.20	138.30	66.50	73.55	86.35	94.20	80.70	66.05
11/8/2022	50.95	48.40	50.10	138.15	154.05	138.15	66.45	73.45	86.25	94.10	80.60	65.95
11/9/2022	50.95	48.40	50.10	138.20	154.10	138.20	66.45	73.45	86.25	94.10	80.60	65.95
11/10/2022	51.55	48.95	50.70	139.85	155.90	139.85	67.25	74.30	87.25	95.30	81.65	66.80
11/11/2022	51.05	48.45	50.20	138.45	154.35	138.45	66.55	73.55	86.35	94.25	80.75	66.05
11/14/2022	52.40	49.75	51.55	142.15	158.50	142.15	68.35	75.55	88.65	97.05	83.15	68.00
11/15/2022	53.10	50.40	52.25	144.05	160.65	144.05	69.25	76.55	89.85	98.20	84.15	68.80

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
April 2020 - March 2021

Idaho Power/102
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Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
11/16/2022	53.95	51.20	53.10	146.35	163.20	146.35	70.35	77.75	91.30	99.95	85.65	70.00
11/17/2022	53.80	51.05	52.95	148.20	165.25	148.20	71.25	78.75	92.45	101.10	86.65	70.80
11/18/2022	53.75	51.00	52.90	148.05	165.10	148.05	71.20	78.65	92.35	101.00	86.55	70.70
11/21/2022	53.80	51.05	52.95	148.25	165.30	148.25	71.30	78.75	92.45	101.10	86.65	70.75
11/22/2022	54.00	51.25	53.15	149.00	166.15	149.00	71.65	79.15	92.90	101.10	86.65	70.75
11/23/2022	54.70	51.95	53.85	151.00	168.35	151.00	72.60	80.20	94.15	102.60	87.95	71.80
11/24/2022	54.70	51.95	53.85	151.00	168.35	151.00	72.60	80.20	94.15	102.60	87.95	71.80
11/25/2022	54.50	51.80	53.65	150.50	167.80	150.50	72.35	79.95	93.85	102.25	87.65	71.55
11/28/2022	55.05	52.35	54.20	152.10	169.55	152.10	73.10	80.80	94.85	103.45	88.65	72.35
11/29/2022	54.65	51.95	53.80	151.00	168.30	151.00	77.80	85.95	100.90	103.45	88.65	72.35
11/30/2022	54.65	51.95	53.80	151.00	168.30	151.00	77.80	85.95	100.90	103.15	88.40	72.15
12/1/2022	54.65	51.95	53.80	151.05	168.40	151.05	77.85	86.00	100.95	103.20	88.45	72.20
12/2/2022	53.80	51.15	52.95	148.70	165.80	148.70	76.65	84.65	99.40	102.30	87.65	71.55
12/5/2022	53.65	51.00	52.80	148.35	165.40	148.35	76.45	84.45	99.15	102.00	87.40	71.35
12/6/2022	53.70	51.05	52.85	148.50	165.55	148.50	76.50	84.55	99.25	102.10	87.50	71.45
12/7/2022	54.70	52.00	53.85	151.35	168.70	151.35	77.95	86.15	101.15	103.70	88.90	72.55
12/8/2022	56.40	53.60	55.50	156.05	173.95	156.05	80.35	88.80	104.30	107.25	91.95	75.05
12/9/2022	57.75	54.85	56.80	159.70	178.05	159.70	82.25	90.90	106.75	110.00	94.30	76.95
12/12/2022	56.10	53.30	55.20	155.15	173.00	155.15	79.90	88.30	103.70	106.55	91.35	74.55
12/13/2022	55.80	53.00	54.90	154.30	172.10	154.30	79.45	87.85	103.15	105.90	90.80	74.10
12/14/2022	55.25	52.50	54.35	152.80	170.40	152.80	78.65	87.00	102.15	103.95	89.15	72.75
12/15/2022	57.25	54.40	56.35	153.25	170.90	153.25	78.90	87.25	102.45	104.75	89.85	73.30
12/16/2022	57.15	54.30	56.25	152.95	170.55	152.95	78.75	87.10	102.25	104.80	89.90	73.35
12/19/2022	56.65	53.85	55.75	151.65	169.10	151.65	78.10	86.35	101.40	103.80	89.05	72.65
12/20/2022	57.95	55.10	57.05	155.20	173.05	155.20	79.95	88.35	103.75	104.20	89.40	72.95
12/21/2022	58.50	55.60	57.60	156.65	174.65	156.65	80.70	89.15	104.70	106.55	91.40	74.60
12/22/2022	58.75	55.85	57.85	157.30	175.40	157.30	81.05	89.55	105.15	108.00	92.65	75.60
12/23/2022	58.85	55.95	57.95	157.55	175.65	157.55	81.15	89.70	105.30	108.20	92.80	75.75
12/27/2022	58.65	55.75	57.75	157.00	175.05	157.00	80.85	89.40	104.95	108.65	93.20	76.05
12/28/2022	58.50	55.60	57.60	156.55	174.55	156.55	80.60	89.15	104.65	108.20	92.80	75.75
12/29/2022	58.20	55.35	57.30	155.80	173.70	155.80	80.20	88.70	104.15	107.65	92.30	75.35

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
April 2020 - March 2021

Idaho Power/102
Brady/3

Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
12/30/2022	58.20	55.35	57.30	155.75	173.65	155.75	80.15	88.65	104.10	107.60	92.25	75.30
1/2/2023	58.20	55.35	57.30	155.75	173.65	155.75	80.15	88.65	104.10	107.60	92.25	75.30
1/3/2023	58.20	55.35	57.30	155.75	173.65	155.75	80.15	88.65	104.10	107.60	92.25	75.30
1/4/2023	57.60	54.80	56.70	154.15	171.85	154.15	79.30	87.75	103.05	106.40	91.20	74.45
1/5/2023	57.35	54.60	56.50	153.55	171.15	153.55	79.00	87.40	102.65	105.95	90.80	74.10
1/6/2023	57.35	54.60	56.50	153.55	171.15	153.55	79.00	87.40	102.65	105.95	90.80	74.10
1/9/2023	57.50	54.75	56.65	154.00	171.65	154.00	79.25	87.65	102.95	106.30	91.10	74.35
1/10/2023	57.50	54.75	56.65	154.00	171.65	154.00	79.25	87.65	102.95	106.30	91.10	74.35
1/11/2023	56.65	53.90	55.80	151.65	169.05	151.65	78.05	86.30	101.40	104.50	89.55	73.10
1/12/2023	56.95	54.20	56.10	152.45	169.95	152.45	78.45	86.75	101.95	105.50	90.40	73.80
1/13/2023	55.90	53.20	55.05	149.60	166.75	149.60	77.00	85.15	100.05	103.35	88.55	72.30
1/16/2023	55.90	53.20	55.05	149.60	166.75	149.60	77.00	85.15	100.05	103.35	88.55	72.30
1/17/2023	54.80	52.15	53.95	146.60	163.40	146.60	75.45	83.45	98.05	101.05	86.60	70.70
1/18/2023	54.40	51.75	53.55	145.50	162.20	145.50	74.90	82.85	97.30	102.00	87.40	71.35
1/19/2023	54.30	51.65	53.45	145.30	161.95	145.30	74.80	82.70	97.15	101.85	87.25	71.25
1/20/2023	53.95	51.35	53.10	144.40	160.95	144.40	74.35	82.20	96.55	103.15	88.40	72.15
1/23/2023	53.90	51.30	53.05	144.30	160.85	144.30	74.30	82.15	96.50	103.10	88.35	72.10
1/24/2023	53.95	51.35	53.10	144.40	160.95	144.40	74.35	82.20	96.55	102.45	87.75	71.65
1/25/2023	52.25	49.75	51.45	139.90	155.95	139.90	72.05	79.65	93.55	99.00	84.80	69.25
1/26/2023	51.85	49.40	51.05	138.85	154.80	138.85	71.50	79.05	92.85	98.20	84.10	68.70
1/27/2023	51.95	49.45	51.15	139.05	155.05	139.05	71.60	79.15	93.00	98.60	84.45	68.95
1/30/2023	51.80	49.30	51.00	138.65	154.65	138.65	71.40	78.95	92.75	98.30	84.20	68.75
1/31/2023	51.85	49.35	51.05	138.80	154.85	138.80	71.50	79.05	92.85	98.45	84.30	68.85
2/1/2023	51.95	49.45	51.15	139.45	155.60	139.45	71.85	79.45	93.30	98.90	84.70	69.15
2/2/2023	50.40	48.00	49.65	140.50	156.80	140.50	72.40	80.05	94.00	99.20	84.95	69.35
2/3/2023	49.05	46.70	48.30	140.50	156.80	140.50	72.40	80.05	94.00	98.80	84.60	69.10
2/6/2023	48.80	46.45	48.05	139.75	155.95	139.75	72.00	79.60	93.50	98.35	84.20	68.75
2/7/2023	48.70	46.35	47.95	139.50	155.70	139.50	71.85	79.45	93.35	98.95	84.70	69.15
2/8/2023	48.40	46.10	47.65	138.65	154.80	138.65	71.45	79.00	92.80	98.30	84.15	68.70
2/9/2023	48.55	46.25	47.80	139.10	155.30	139.10	71.70	79.25	93.10	98.65	84.45	68.95
2/10/2023	48.80	46.50	48.05	139.85	156.15	139.85	72.10	79.70	93.60	98.95	84.70	69.15

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
April 2020 - March 2021

Idaho Power/102
Brady/4

Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
2/13/2023	48.10	45.85	47.35	137.85	153.90	137.85	71.05	78.55	92.25	97.45	83.40	68.10
2/14/2023	49.05	46.75	48.30	140.55	156.90	140.55	72.45	80.10	94.05	99.05	84.75	69.20
2/15/2023	49.45	47.10	48.65	141.60	158.10	141.60	73.00	80.70	94.75	99.85	85.45	69.75
2/16/2023	50.00	47.65	49.20	143.20	159.90	143.20	73.80	81.60	95.80	101.05	86.50	70.60
2/17/2023	50.20	47.85	49.40	143.80	160.60	143.80	74.10	81.95	96.20	101.50	86.90	70.90
2/21/2023	50.00	47.65	49.20	143.15	159.90	143.15	73.75	81.60	95.75	101.00	86.50	70.55
2/22/2023	50.15	47.75	49.30	143.50	160.30	143.50	73.95	81.80	96.00	100.70	86.25	70.35
2/23/2023	50.95	48.55	50.10	145.85	162.90	145.85	75.15	83.15	97.55	102.05	87.45	71.30
2/24/2023	51.45	49.00	50.55	147.20	164.40	147.20	75.85	83.95	98.45	102.65	87.95	71.70
2/27/2023	51.50	49.05	50.60	147.40	164.65	147.40	75.95	84.05	98.60	102.80	88.10	71.80
2/28/2023	51.05	48.65	50.15	157.40	179.90	146.15	75.30	83.35	97.75	103.85	89.00	72.55
3/1/2023	51.20	48.80	50.30	157.90	180.45	146.65	75.55	83.60	98.05	104.20	89.30	72.80
3/2/2023	51.45	49.05	50.55	158.65	181.35	147.35	75.90	84.00	98.55	104.75	89.75	73.20
3/3/2023	51.70	49.30	50.80	159.40	182.20	148.05	76.25	84.40	99.00	107.10	91.75	74.85
3/6/2023	51.40	49.00	50.50	158.50	181.20	147.20	75.80	83.95	98.45	106.75	91.45	74.60
3/7/2023	51.60	49.20	50.70	159.05	181.85	147.75	76.05	84.25	98.80	107.15	91.80	74.90
3/8/2023	53.05	50.55	52.10	163.45	186.90	151.85	78.15	86.60	101.55	110.25	94.45	77.05
3/9/2023	52.95	50.45	52.00	163.10	186.50	151.55	78.00	86.40	101.35	110.25	94.45	77.05
3/10/2023	52.60	50.15	51.65	162.05	185.30	150.60	77.50	85.85	100.70	109.50	93.80	76.55
3/13/2023	52.75	50.30	51.80	162.55	185.85	151.05	77.75	86.10	101.00	110.20	94.40	77.05
3/14/2023	52.50	50.10	51.60	161.85	185.05	150.40	77.40	85.75	100.55	109.70	93.95	76.70
3/15/2023	52.45	50.05	51.55	161.75	184.95	150.30	77.35	85.70	100.50	109.65	93.90	76.65
3/16/2023	53.05	50.65	52.15	163.65	187.15	152.10	78.25	86.70	101.70	110.40	94.55	77.15
3/17/2023	52.95	50.55	52.05	163.35	186.80	151.80	78.10	86.55	101.50	111.00	95.10	77.60
3/20/2023	56.20	53.65	55.25	160.90	184.00	149.50	82.90	91.85	107.75	112.15	96.10	78.40
3/21/2023	56.95	54.35	56.00	163.05	186.45	151.50	84.00	93.10	109.20	113.25	97.05	79.15
3/22/2023	57.05	54.45	56.10	163.30	186.75	151.75	84.10	93.25	109.35	113.25	97.05	79.15
3/23/2023	56.45	53.85	55.50	161.55	184.70	150.10	83.20	92.25	108.15	112.05	96.00	78.30
3/24/2023	56.50	53.90	55.55	161.75	184.95	150.30	83.30	92.35	108.30	112.00	95.95	78.25
3/27/2023	57.05	54.45	56.10	163.35	186.75	151.80	84.10	93.25	109.35	112.25	96.15	78.40
3/28/2023	57.55	54.90	56.60	165.40	189.10	153.70	85.15	94.40	110.70	114.75	98.30	80.15

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
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Idaho Power/102
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Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
3/29/2023	57.05	54.40	56.10	170.30	194.70	158.25	87.65	97.20	113.95	117.70	100.80	82.20
3/30/2023	56.75	54.15	55.80	169.50	193.75	157.50	87.25	96.75	113.40	117.00	100.20	81.70
3/31/2023	56.30	53.70	55.35	168.10	192.15	156.20	86.55	95.95	112.50	116.00	99.35	81.00
4/3/2023	56.25	53.65	55.30	167.95	191.95	156.05	86.45	95.85	112.40	115.90	99.25	80.90
4/4/2023	56.00	53.40	55.05	167.25	191.15	155.40	86.10	95.45	111.95	115.30	98.70	80.45
4/5/2023	56.05	53.45	55.10	167.45	191.40	155.60	86.20	95.55	112.10	116.30	99.55	81.15
4/6/2023	55.40	52.80	54.45	165.45	189.10	153.75	85.15	94.40	110.75	114.85	98.30	80.10
4/10/2023	55.20	52.60	54.25	164.85	188.40	153.20	84.85	94.05	110.35	114.40	97.90	79.80
4/11/2023	54.85	52.30	53.90	163.85	187.25	152.25	84.35	93.45	109.65	113.60	97.20	79.25
4/12/2023	55.50	52.90	54.50	165.75	189.40	154.00	85.35	94.55	110.90	114.70	98.15	80.05
4/13/2023	55.45	52.90	54.45	165.60	189.20	153.85	85.25	94.45	110.80	115.15	98.55	80.35
4/14/2023	54.65	52.15	53.65	163.20	186.45	151.60	84.00	93.10	109.20	114.40	97.90	79.85
4/17/2023	54.60	52.10	53.60	163.05	186.30	151.50	83.95	93.05	109.10	114.30	97.80	79.80
4/18/2023	54.35	51.85	53.35	162.25	185.40	150.75	83.55	92.60	108.55	113.70	97.30	79.40
4/19/2023	54.30	51.80	53.30	162.15	185.30	150.65	83.50	92.55	108.50	113.65	97.25	79.35
4/20/2023	54.05	51.55	53.05	161.35	184.40	149.95	83.10	92.10	108.00	113.10	96.75	78.95
4/21/2023	53.60	51.10	52.60	160.00	182.90	148.70	82.40	91.35	107.10	112.15	95.90	78.25
4/24/2023	52.65	50.20	51.70	157.25	179.75	146.10	80.95	89.75	105.25	110.15	94.20	76.85
4/25/2023	53.00	50.55	52.05	158.30	180.95	147.10	81.50	90.35	105.95	110.90	94.85	77.40
4/26/2023	52.55	50.10	51.60	156.90	179.35	145.80	80.80	89.55	105.00	109.90	94.00	76.70
4/27/2023	52.25	49.80	51.30	155.95	178.30	144.95	80.30	89.00	104.35	110.05	94.15	76.80
4/28/2023	52.65	50.15	51.70	157.10	179.65	146.05	80.90	89.65	105.15	110.45	94.50	77.05
5/1/2023	52.35	49.85	51.40	156.15	178.55	145.15	80.40	89.10	104.50	109.75	93.90	76.55
5/2/2023	52.45	49.95	51.50	156.45	178.90	145.45	80.55	89.30	104.70	110.50	94.55	77.10
5/3/2023	51.95	49.50	51.00	154.75	177.20	144.10	79.80	88.45	103.70	109.40	93.60	76.35
5/4/2023	51.30	48.90	50.40	152.80	175.05	142.35	78.85	87.35	102.45	108.05	92.45	75.40
5/5/2023	51.30	48.90	50.40	152.80	175.05	142.35	78.85	87.35	102.45	108.05	92.45	75.40
5/8/2023	52.10	49.70	51.20	149.45	177.80	144.60	80.10	88.75	104.10	109.25	93.50	76.25
5/9/2023	52.90	50.45	51.95	149.10	177.95	144.75	80.20	88.85	104.20	109.90	94.10	76.70
5/10/2023	53.55	51.05	52.60	149.85	180.10	146.50	77.95	86.35	101.30	110.10	94.30	76.85
5/11/2023	53.60	51.10	52.65	149.65	180.25	146.65	78.00	86.45	101.40	110.30	94.50	77.00

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
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Idaho Power/102
Brady/6

Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
5/12/2023	54.05	51.55	53.10	149.70	181.75	147.90	78.65	87.20	102.25	112.45	96.35	78.50
5/15/2023	54.25	51.70	53.25	149.70	182.35	148.40	78.90	87.50	102.60	113.20	97.00	79.00
5/16/2023	54.10	51.55	53.10	149.30	181.85	148.00	78.70	87.25	102.35	113.05	96.85	78.90
5/17/2023	54.20	51.65	53.20	149.60	182.20	148.30	78.85	87.45	102.55	113.30	97.05	79.05
5/18/2023	54.35	51.80	53.35	150.05	182.75	148.75	79.10	87.70	102.85	113.65	97.35	79.30
5/19/2023	54.25	51.70	53.25	149.70	182.35	148.40	78.90	87.50	102.60	113.35	97.10	79.10
5/22/2023	54.10	51.55	53.10	149.30	181.90	148.00	78.70	87.25	102.35	113.35	97.10	79.10
5/23/2023	54.10	51.55	53.10	149.30	181.90	148.00	78.70	87.25	102.35	113.35	97.10	79.10
5/24/2023	55.35	52.75	54.35	152.75	186.15	151.45	80.55	89.30	104.75	115.25	98.70	80.40
5/25/2023	55.35	52.75	54.35	152.70	186.15	151.45	80.55	89.30	104.75	115.25	98.70	80.40
5/26/2023	55.15	52.55	54.15	152.15	185.45	150.90	80.25	89.00	104.35	114.80	98.35	80.10
5/30/2023	55.10	52.50	54.10	151.95	185.20	150.70	80.15	88.90	104.20	114.65	98.20	80.00
5/31/2023	55.00	52.40	54.00	151.70	184.95	150.50	80.05	88.75	104.05	114.50	98.05	79.90
5/29/2023	55.15	52.55	54.15	152.15	185.45	150.90	80.25	89.00	104.35	114.80	98.35	80.10
6/1/2023	54.50	51.90	53.50	150.30	183.25	149.10	79.30	87.95	103.10	113.45	97.15	79.15
6/2/2023	53.95	51.40	52.95	148.80	181.40	147.60	78.50	87.05	102.05	112.55	96.35	78.50
6/5/2023	54.00	51.45	53.00	148.90	181.50	147.70	78.55	87.10	102.10	112.60	96.40	78.55
6/6/2023	53.65	51.10	52.65	147.85	180.25	146.70	78.00	86.50	101.40	112.15	96.00	78.20
6/7/2023	54.10	51.50	53.05	149.05	181.70	147.90	78.65	87.20	102.20	112.75	96.50	78.60
6/8/2023	54.00	51.40	52.95	148.75	181.35	147.60	78.50	87.00	102.00	115.15	98.55	80.25
6/9/2023	54.20	51.60	53.15	149.25	182.00	148.10	78.75	87.30	102.35	115.55	98.90	80.50
6/12/2023	54.25	51.65	53.20	149.40	182.20	148.25	78.85	87.40	102.45	115.65	99.00	80.55
6/13/2023	54.35	51.75	53.30	149.65	182.50	148.50	79.00	87.55	102.60	115.85	99.15	80.65
6/14/2023	54.35	51.75	53.30	149.65	182.50	148.50	79.00	87.55	102.60	115.85	99.15	80.65
6/15/2023	54.70	52.10	53.65	150.60	183.65	149.45	79.50	88.10	103.25	116.60	99.80	81.15
6/16/2023	54.55	51.95	53.50	150.15	183.10	149.00	79.25	87.85	102.95	115.65	99.00	80.50
6/20/2023	54.25	51.70	53.25	149.40	182.15	148.25	78.85	87.40	102.40	114.80	98.25	79.90
6/21/2023	55.05	52.50	54.05	151.65	184.90	150.50	80.05	88.70	103.95	116.55	99.75	81.10
6/22/2023	54.80	52.25	53.80	151.00	184.10	149.85	79.70	88.30	103.50	115.40	98.75	80.30
6/23/2023	54.75	52.20	53.75	150.85	183.90	149.70	79.60	88.20	103.40	115.25	98.65	80.20
6/26/2023	54.75	52.20	53.75	150.85	183.90	149.70	79.60	88.20	103.40	115.25	98.65	80.20

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
April 2020 - March 2021

Idaho Power/102
Brady/7

Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
6/27/2023	54.00	51.50	53.05	148.85	181.45	147.70	78.55	87.05	102.05	113.70	97.35	79.15
6/28/2023	54.00	51.50	53.05	148.85	181.45	147.70	78.55	87.05	102.05	113.70	97.35	79.15
6/29/2023	54.15	51.65	53.20	149.25	181.95	148.10	78.75	87.30	102.30	114.00	97.60	79.35
6/30/2023	54.00	51.50	53.05	148.85	181.45	147.70	78.55	87.05	102.00	112.80	96.60	78.50
7/3/2023	54.00	51.50	53.05	148.85	181.45	147.70	78.55	87.05	102.00	112.80	96.60	78.50
7/5/2023	53.80	51.30	52.85	148.35	180.80	147.20	78.25	86.75	101.65	112.40	96.25	78.20
7/6/2023	53.60	51.10	52.65	147.85	180.20	146.70	78.00	86.45	101.30	111.75	95.70	77.75
7/7/2023	53.85	51.35	52.90	148.60	181.10	147.45	78.40	86.90	101.80	111.25	95.30	77.40
7/10/2023	53.95	51.45	53.00	148.90	181.45	147.75	78.55	87.05	102.00	111.50	95.50	77.55
7/11/2023	54.20	51.70	53.25	149.60	182.30	148.45	78.90	87.45	102.45	111.10	95.15	77.30
7/12/2023	53.65	51.20	52.70	148.10	180.45	146.95	78.10	86.55	101.40	109.95	94.15	76.50
7/13/2023	53.25	50.80	52.30	147.00	179.10	145.85	77.50	85.90	100.65	109.10	93.40	75.90
7/14/2023	53.70	51.25	52.75	148.25	180.65	147.10	78.15	86.65	101.50	109.95	94.15	76.50
7/17/2023	53.75	51.30	52.80	148.40	180.85	147.25	78.25	86.75	101.60	110.05	94.25	76.60
7/18/2023	53.45	51.00	52.50	147.55	179.85	146.40	77.80	86.25	101.05	108.90	93.25	75.80
7/19/2023	53.65	51.20	52.70	148.10	180.50	146.95	78.10	86.55	101.40	109.35	93.65	76.10
7/20/2023	53.50	51.05	52.55	147.65	179.90	146.50	77.85	86.25	101.05	109.00	93.35	75.85
7/21/2023	53.55	51.10	52.60	147.85	180.15	146.70	77.95	86.35	101.20	109.15	93.50	75.95
7/24/2023	53.85	51.35	52.90	148.60	181.10	147.45	78.35	86.80	101.75	109.75	94.00	76.35
7/25/2023	53.90	51.40	52.95	148.75	181.30	147.60	78.45	86.90	101.85	109.90	94.10	76.45
7/26/2023	54.45	51.95	53.50	150.30	183.20	149.15	79.25	87.80	102.90	111.10	95.10	77.25
7/27/2023	55.15	52.65	54.20	150.60	183.55	149.45	80.30	88.95	104.25	111.55	95.50	77.55
7/28/2023	55.80	53.30	54.85	152.45	185.80	151.25	81.25	90.05	105.50	112.30	96.15	78.10
7/31/2023	55.25	52.80	54.30	151.00	184.00	149.80	80.45	89.20	104.50	111.15	95.20	77.30
8/1/2023	55.05	52.65	54.10	150.50	183.40	149.30	80.20	88.90	104.15	110.75	94.90	77.05
8/2/2023	55.25	52.85	54.30	150.60	183.55	149.40	80.50	89.25	104.55	111.40	95.45	77.50
8/3/2023	55.95	53.50	54.95	151.10	184.15	149.90	81.50	90.35	105.85	112.40	96.30	78.20
8/4/2023	55.70	53.25	54.70	150.40	183.30	149.20	81.10	89.95	105.35	111.85	95.80	77.80
8/7/2023	55.50	53.05	54.50	149.80	182.60	148.65	80.80	89.60	104.95	111.40	95.40	77.50
8/8/2023	55.00	52.55	54.00	148.45	180.95	147.30	80.05	88.80	104.00	110.35	94.50	76.80
8/9/2023	55.95	53.45	54.90	147.60	179.90	146.45	81.40	90.30	105.75	111.65	95.65	77.70

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
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Idaho Power/102
 Brady/8

Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
8/10/2023	56.30	53.80	55.25	147.85	180.20	146.70	81.90	90.85	106.40	112.15	96.10	78.05
8/11/2023	56.35	53.85	55.30	143.95	175.45	142.80	82.00	90.95	106.50	111.00	95.10	77.25
8/14/2023	56.00	53.55	54.95	143.10	174.40	141.95	81.50	90.40	105.85	112.15	96.10	78.05
8/15/2023	57.05	54.55	56.00	139.45	174.05	141.65	83.05	92.10	107.85	113.05	96.85	78.65
8/16/2023	56.60	54.15	55.55	137.60	171.75	139.80	82.40	91.40	107.00	111.95	95.90	77.85
8/17/2023	56.30	53.85	55.25	136.85	170.80	139.00	81.95	90.90	106.40	111.30	95.35	77.40
8/18/2023	56.65	54.15	55.60	135.80	169.45	137.90	82.45	91.45	107.05	111.10	95.15	77.25

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
April 2020 - March 2021

Idaho Power/102
Brady/9

Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
8/21/2023	56.70	54.20	55.65	135.95	169.65	138.10	82.55	91.55	107.20	111.25	95.25	77.35
8/22/2023	56.00	53.55	55.00	134.30	167.60	136.45	81.55	90.45	105.90	109.90	94.10	76.40
8/23/2023	55.85	53.40	54.85	133.90	167.10	136.05	81.30	90.15	105.55	109.90	94.10	76.40
8/24/2023	55.25	52.85	54.30	132.50	165.35	134.65	80.45	89.20	104.45	108.75	93.10	75.60
8/25/2023	55.55	53.15	54.60	133.20	166.20	135.35	80.85	89.65	105.00	109.90	94.10	76.40
8/28/2023	54.90	52.55	53.95	131.65	164.25	133.75	79.90	88.60	103.80	109.55	93.80	76.15
8/29/2023	54.65	52.30	53.70	130.40	162.70	132.50	79.50	88.20	103.30	108.85	93.20	75.65
8/30/2023	54.55	52.20	53.60	130.15	162.35	132.25	79.35	88.00	103.10	108.65	93.00	75.50
8/31/2023	54.45	52.10	53.50	129.90	162.05	132.00	79.20	87.85	102.90	108.45	92.85	75.35
9/1/2023	54.55	52.20	53.60	130.15	162.35	132.25	79.35	88.00	103.10	108.65	93.05	75.50
9/5/2023	53.50	51.20	52.60	127.70	159.25	129.75	77.85	86.35	101.15	106.60	91.30	74.05
9/6/2023	53.30	51.00	52.40	127.25	158.70	129.30	77.60	86.05	100.80	106.25	91.00	73.80
9/7/2023	53.15	50.85	52.25	126.90	158.30	128.95	77.40	85.80	100.55	105.95	90.75	73.60
9/8/2023	52.85	50.55	51.95	126.20	157.40	128.20	76.95	85.30	100.00	105.35	90.25	73.20
9/11/2023	53.50	51.15	52.55	127.70	159.30	129.75	77.90	86.35	101.20	106.60	91.35	74.10
9/12/2023	53.95	51.55	53.00	128.75	160.60	130.80	78.55	87.05	102.05	106.10	90.90	73.75
9/13/2023	54.50	52.10	53.55	130.10	162.30	132.15	79.35	87.95	103.10	107.25	91.85	74.55
9/14/2023	54.80	52.40	53.85	130.80	163.15	132.85	79.80	88.40	103.65	107.85	92.35	74.95
9/15/2023	54.25	51.90	53.30	129.50	161.55	131.55	79.00	87.55	102.65	106.80	91.45	74.20
9/18/2023	53.25	50.95	52.30	127.10	158.55	129.10	77.55	85.95	100.75	104.80	89.75	72.80
9/19/2023	53.65	51.35	52.70	128.05	159.70	130.05	78.10	86.60	101.50	106.35	91.05	73.85
9/20/2023	54.30	51.95	53.30	129.55	161.55	131.55	79.00	87.60	102.70	107.60	92.15	74.70
9/21/2023	56.60	54.15	55.55	135.00	168.35	137.05	76.65	85.00	99.65	105.90	90.65	73.50
9/22/2023	55.30	52.90	54.25	131.85	164.40	133.85	74.85	83.00	97.30	107.25	91.80	74.45
9/25/2023	54.85	52.45	53.80	130.75	163.00	132.70	74.20	82.30	96.50	107.95	92.40	74.95
9/26/2023	54.50	52.10	53.45	129.95	161.95	131.85	73.75	81.80	95.90	107.25	91.80	74.45
9/27/2023	55.35	52.90	54.30	132.00	164.50	133.90	74.90	83.10	97.40	108.95	93.25	75.65
9/28/2023	55.35	52.90	54.30	132.00	164.50	133.90	74.90	83.10	97.40	108.95	93.25	75.65
9/29/2023	56.10	53.60	55.00	133.75	166.65	135.65	75.90	84.20	98.70	110.05	94.20	76.40
10/2/2023	56.10	53.60	55.00	133.75	166.65	135.65	75.90	84.20	98.70	110.05	94.20	76.40
10/3/2023	56.80	54.30	55.70	134.70	167.80	136.60	76.85	85.25	99.95	110.70	94.75	76.85

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
 April 2020 - March 2021

Idaho Power/102
 Brady/10

Mid-C HL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
Average	53.42	50.91	52.51	146.11	170.32	143.88	76.33	84.54	99.15	105.56	90.41	73.67
Max HL	58.85	55.95	57.95	170.30	194.70	159.70	87.65	97.20	113.95	117.70	100.80	82.20
Min HL	38.35	36.35	37.65	110.90	123.60	110.90	53.30	59.05	69.25	69.85	59.90	49.05
Spread	20.50	19.60	20.30	59.40	71.10	48.80	34.35	38.15	44.70	47.85	40.90	33.15

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
April 2020 - March 2021

Idaho Power/102
Brady/11

Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
10/4/2022	30.55	25.45	24.75	79.50	90.40	83.55	45.30	50.05	57.65	66.40	58.60	48.90
10/5/2022	30.95	25.80	25.10	80.60	91.65	84.65	45.85	50.65	58.35	67.20	59.30	49.45
10/6/2022	31.55	26.45	25.80	82.50	93.70	86.45	46.65	51.50	59.40	68.30	60.25	50.20
10/7/2022	33.65	28.60	28.15	78.65	89.30	82.40	44.40	49.00	56.55	68.90	60.75	50.60
10/10/2022	33.50	28.45	28.00	78.30	88.90	82.05	44.25	48.80	56.35	68.65	60.50	50.40
10/11/2022	34.55	29.45	29.05	81.25	92.20	85.00	45.65	50.35	58.20	70.95	62.45	52.00
10/12/2022	35.50	30.35	30.00	83.75	95.00	87.50	46.85	51.70	59.75	72.85	64.05	53.30
10/13/2022	35.25	30.15	29.75	83.15	94.30	86.90	46.55	51.40	59.35	73.25	64.40	53.60
10/14/2022	35.25	30.15	29.75	83.15	94.30	86.90	46.55	51.40	59.35	73.25	64.40	53.60
10/17/2022	35.55	30.45	30.05	83.95	95.15	87.70	46.90	51.80	59.85	74.40	65.40	54.40
10/18/2022	35.25	30.15	29.75	83.10	94.20	86.85	46.50	51.35	59.30	75.55	66.40	55.20
10/19/2022	34.85	29.80	29.35	80.70	91.55	84.45	45.35	50.10	57.80	73.90	65.00	54.05
10/20/2022	34.45	29.45	29.00	79.70	90.45	83.45	44.90	49.55	57.20	73.15	64.35	53.55
10/21/2022	32.90	28.00	27.50	75.70	86.00	79.45	42.95	47.40	54.70	70.15	61.75	51.45
10/24/2022	33.50	28.55	28.10	77.25	87.70	81.00	43.70	48.20	55.65	71.30	62.75	52.25
10/25/2022	35.25	30.25	29.90	81.95	92.95	85.65	45.85	50.60	58.45	71.20	62.55	52.05
10/26/2022	35.40	30.50	30.20	82.65	93.65	86.20	46.00	50.75	58.65	71.35	62.60	52.05
10/27/2022	35.55	30.70	30.45	83.30	94.30	86.75	46.15	50.90	58.85	71.50	62.70	52.10
10/28/2022	35.50	30.65	30.40	83.25	94.25	86.70	46.10	50.85	58.80	71.45	62.65	52.05
10/31/2022	35.85	31.00	30.75	86.35	97.70	89.80	47.60	52.50	60.75	72.35	63.40	52.65
11/1/2022	35.75	30.90	30.65	86.15	97.50	89.60	47.50	52.40	60.65	72.20	63.25	52.55
11/2/2022	36.60	31.65	31.40	89.70	101.50	93.25	49.35	54.45	63.00	75.85	66.40	55.15
11/3/2022	37.80	32.80	32.55	92.90	105.10	96.45	50.90	56.15	65.00	77.05	67.45	56.00
11/4/2022	37.75	32.80	32.60	92.90	105.10	96.40	50.80	56.00	64.85	78.10	68.35	56.70
11/7/2022	37.90	32.95	32.75	94.20	106.50	97.70	51.40	56.70	65.65	78.95	69.10	57.30
11/8/2022	37.45	32.55	32.35	93.10	105.30	96.60	50.80	56.05	64.90	78.05	68.35	56.65
11/9/2022	37.45	32.55	32.35	93.15	105.35	96.65	50.80	56.05	64.90	78.05	68.35	56.65
11/10/2022	38.05	33.10	32.95	94.80	107.15	98.30	51.60	56.90	65.90	79.25	69.40	57.50
11/11/2022	37.55	32.60	32.45	93.40	105.60	96.90	50.90	56.15	65.00	78.20	68.50	56.75
11/14/2022	38.60	33.60	33.50	96.30	108.80	99.75	52.25	57.65	66.75	79.75	69.80	57.80
11/15/2022	39.45	34.40	34.30	98.55	111.30	102.00	53.35	58.85	68.20	81.75	71.55	59.25

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
April 2020 - March 2021

Idaho Power/102
Brady/12

Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
11/16/2022	40.15	35.10	35.00	100.50	113.45	103.95	54.25	59.85	69.40	83.20	72.75	60.25
11/17/2022	40.00	34.95	34.85	102.35	115.50	105.80	55.15	60.85	70.55	84.35	73.75	61.05
11/18/2022	39.95	34.90	34.80	102.20	115.35	105.65	55.10	60.75	70.45	84.25	73.65	60.95
11/21/2022	39.55	34.55	34.45	101.30	114.30	104.70	54.60	60.20	69.80	83.80	73.25	60.60
11/22/2022	39.50	34.50	34.40	101.40	114.40	104.75	54.60	60.20	69.80	83.80	73.25	60.60
11/23/2022	40.20	35.20	35.10	103.40	116.60	106.75	55.55	61.25	71.05	85.30	74.55	61.65
11/24/2022	40.20	35.20	35.10	103.40	116.60	106.75	55.55	61.25	71.05	85.30	74.55	61.65
11/25/2022	40.00	35.05	34.90	102.90	116.05	106.25	55.30	61.00	70.75	84.95	74.25	61.40
11/28/2022	40.55	35.60	35.45	104.50	117.80	107.85	56.05	61.85	71.75	86.10	75.25	62.20
11/29/2022	38.10	33.45	33.30	98.15	110.65	101.35	57.65	63.65	73.90	82.05	71.70	59.25
11/30/2022	38.10	33.45	33.30	98.15	110.65	101.35	57.65	63.65	73.90	83.70	73.15	60.45
12/1/2022	38.10	33.45	33.30	98.20	110.75	101.40	57.70	63.70	73.95	83.75	73.20	60.50
12/2/2022	38.85	34.05	33.85	100.00	112.85	103.35	58.95	65.05	75.50	82.50	72.10	59.60
12/5/2022	38.60	33.80	33.60	99.30	112.05	102.65	58.55	64.60	75.00	82.00	71.65	59.25
12/6/2022	38.65	33.85	33.65	99.45	112.20	102.80	58.60	64.70	75.10	82.10	71.75	59.35
12/7/2022	39.15	34.35	34.20	100.95	113.85	104.25	59.25	65.45	75.95	83.70	73.10	60.45
12/8/2022	40.85	35.95	35.85	105.65	119.10	108.95	61.65	68.10	79.10	87.25	76.15	62.95
12/9/2022	41.60	36.70	36.65	107.85	121.55	111.10	62.70	69.25	80.45	88.35	77.05	63.70
12/12/2022	39.95	35.15	35.05	103.30	116.50	106.55	60.35	66.65	77.40	84.90	74.10	61.30
12/13/2022	39.65	34.85	34.75	102.45	115.60	105.70	59.90	66.20	76.85	84.25	73.55	60.85
12/14/2022	39.95	35.05	34.95	103.10	116.35	106.45	60.40	66.75	77.45	83.75	73.15	60.55
12/15/2022	42.20	37.20	37.15	104.20	117.55	107.55	61.00	67.40	78.20	84.85	74.10	61.30
12/16/2022	42.25	37.20	37.15	104.25	117.60	107.60	61.05	67.45	78.25	84.90	74.15	61.35
12/19/2022	41.75	36.75	36.65	102.95	116.15	106.30	60.40	66.70	77.40	83.90	73.30	60.65
12/20/2022	41.95	37.05	37.00	103.75	117.00	107.00	60.60	66.95	77.70	84.35	73.65	60.95
12/21/2022	42.35	37.45	37.40	104.85	118.20	108.05	61.15	67.55	78.40	84.80	74.00	61.25
12/22/2022	42.60	37.70	37.65	105.50	118.95	108.70	61.50	67.95	78.85	86.25	75.25	62.25
12/23/2022	42.70	37.80	37.75	105.75	119.20	108.95	61.60	68.10	79.00	86.45	75.40	62.40
12/27/2022	42.35	37.50	37.40	104.85	118.20	108.05	61.10	67.55	78.35	84.85	74.00	61.25
12/28/2022	42.05	37.25	37.15	104.15	117.40	107.30	60.70	67.10	77.85	84.50	73.70	61.00
12/29/2022	42.20	37.40	37.25	104.50	117.80	107.70	60.95	67.40	78.20	84.65	73.80	61.10

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
April 2020 - March 2021

Idaho Power/102
Brady/13

Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
12/30/2022	42.25	37.40	37.25	104.55	117.85	107.75	61.00	67.45	78.25	84.65	73.80	61.10
1/2/2023	42.25	37.40	37.25	104.55	117.85	107.75	61.00	67.45	78.25	84.65	73.80	61.10
1/3/2023	42.25	37.40	37.25	104.55	117.85	107.75	61.00	67.45	78.25	84.65	73.80	61.10
1/4/2023	41.65	36.85	36.65	102.95	116.05	106.15	60.15	66.55	77.20	83.45	72.75	60.25
1/5/2023	41.95	37.10	36.90	103.70	116.90	106.95	60.65	67.10	77.80	84.65	73.80	61.10
1/6/2023	41.95	37.10	36.90	103.70	116.90	106.95	60.65	67.10	77.80	84.65	73.80	61.10
1/9/2023	42.10	37.25	37.05	104.15	117.40	107.40	60.90	67.35	78.10	85.00	74.10	61.35
1/10/2023	42.10	37.25	37.05	104.15	117.40	107.40	60.90	67.35	78.10	85.00	74.10	61.35
1/11/2023	41.25	36.40	36.20	101.80	114.80	105.05	59.70	66.00	76.55	83.20	72.55	60.10
1/12/2023	41.55	36.70	36.50	102.60	115.70	105.85	60.10	66.45	77.10	84.65	73.80	61.10
1/13/2023	40.50	35.70	35.45	99.75	112.50	103.00	58.65	64.85	75.20	82.50	71.95	59.60
1/16/2023	40.50	35.70	35.45	99.75	112.50	103.00	58.65	64.85	75.20	82.50	71.95	59.60
1/17/2023	39.40	34.65	34.35	96.75	109.15	100.00	57.10	63.15	73.20	80.20	70.00	58.00
1/18/2023	38.90	34.15	33.85	95.40	107.65	98.65	56.40	62.35	72.25	80.95	70.60	58.50
1/19/2023	38.80	34.05	33.75	95.20	107.40	98.45	56.30	62.20	72.10	80.95	70.60	58.50
1/20/2023	38.45	33.75	33.40	94.30	106.40	97.55	55.85	61.70	71.50	79.15	69.05	57.20
1/23/2023	38.30	33.60	33.25	93.95	106.00	97.20	55.65	61.50	71.25	78.55	68.55	56.80
1/24/2023	38.00	33.35	33.00	93.20	105.15	96.45	55.20	61.00	70.70	77.90	68.00	56.35
1/25/2023	36.30	31.75	31.35	88.70	100.15	91.95	52.90	58.45	67.70	74.45	65.05	53.95
1/26/2023	35.90	31.40	30.95	87.65	99.00	90.90	52.35	57.85	67.00	73.65	64.35	53.40
1/27/2023	35.65	31.20	30.75	87.05	98.30	90.25	52.00	57.45	66.50	73.10	63.90	53.00
1/30/2023	35.50	31.05	30.60	86.60	97.80	89.80	51.75	57.20	66.20	72.45	63.35	52.55
1/31/2023	35.55	31.10	30.65	86.75	98.00	89.95	51.85	57.30	66.30	72.60	63.45	52.65
2/1/2023	35.65	31.20	30.75	87.40	98.75	90.60	52.20	57.70	66.75	73.05	63.85	52.95
2/2/2023	34.10	29.75	29.25	88.45	99.90	91.65	52.75	58.30	67.45	72.75	63.55	52.70
2/3/2023	32.75	28.45	27.90	88.45	99.90	91.65	52.75	58.30	67.45	72.35	63.20	52.45
2/6/2023	32.50	28.20	27.65	87.70	99.05	90.90	52.35	57.85	66.95	71.90	62.80	52.10
2/7/2023	32.40	28.10	27.55	87.45	98.75	90.65	52.20	57.70	66.80	72.50	63.30	52.50
2/8/2023	32.20	27.90	27.35	86.90	98.15	90.10	51.95	57.40	66.45	71.80	62.70	52.00
2/9/2023	32.25	27.95	27.40	87.00	98.25	90.20	52.00	57.45	66.50	72.15	63.00	52.25
2/10/2023	32.30	28.00	27.45	87.15	98.40	90.30	52.00	57.45	66.55	72.65	63.45	52.60

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
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Idaho Power/102
Brady/14

Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
2/13/2023	31.60	27.35	26.75	85.15	96.15	88.30	50.95	56.30	65.20	71.15	62.15	51.55
2/14/2023	32.45	28.15	27.60	87.55	98.85	90.70	52.15	57.65	66.80	71.75	62.65	51.95
2/15/2023	32.85	28.50	27.95	88.60	100.05	91.75	52.70	58.25	67.50	72.55	63.35	52.50
2/16/2023	33.40	29.00	28.50	90.15	101.80	93.30	53.50	59.15	68.55	73.65	64.30	53.25
2/17/2023	33.45	29.05	28.55	90.35	102.00	93.45	53.55	59.20	68.65	73.90	64.50	53.40
2/21/2023	33.25	28.85	28.35	89.70	101.30	92.80	53.20	58.85	68.20	73.40	64.10	53.05
2/22/2023	33.40	28.95	28.45	90.05	101.70	93.15	53.40	59.05	68.45	73.10	63.85	52.85
2/23/2023	34.45	29.95	29.45	93.10	105.10	96.20	55.00	60.85	70.55	74.35	64.90	53.70
2/24/2023	34.65	30.20	29.70	93.80	105.85	96.85	55.30	61.20	70.95	76.30	66.60	55.10
2/27/2023	34.70	30.25	29.75	94.00	106.10	97.05	55.40	61.30	71.10	76.45	66.75	55.20
2/28/2023	34.30	29.85	29.35	99.00	114.10	95.90	54.80	60.65	70.35	77.50	67.65	55.95
3/1/2023	34.45	30.00	29.50	99.50	114.65	96.40	55.05	60.90	70.65	77.85	67.95	56.20
3/2/2023	34.70	30.25	29.75	100.25	115.55	97.10	55.40	61.30	71.15	78.40	68.40	56.60
3/3/2023	35.20	30.70	30.20	101.80	117.30	98.55	56.20	62.15	72.15	79.00	68.90	57.00
3/6/2023	34.85	30.40	29.90	100.80	116.15	97.60	55.70	61.60	71.50	78.55	68.50	56.65
3/7/2023	35.05	30.60	30.10	101.35	116.80	98.15	55.95	61.90	71.85	78.95	68.85	56.95
3/8/2023	35.80	31.40	30.95	103.80	119.60	100.35	57.00	63.05	73.20	80.85	70.50	58.25
3/9/2023	37.15	32.55	32.10	107.65	124.05	104.10	59.15	65.40	75.95	82.90	72.25	59.70
3/10/2023	36.80	32.25	31.75	106.60	122.85	103.15	58.65	64.85	75.30	82.15	71.60	59.20
3/13/2023	36.80	32.25	31.75	106.65	122.90	103.15	58.65	64.85	75.30	82.85	72.20	59.70
3/14/2023	36.55	32.05	31.55	105.95	122.10	102.50	58.30	64.50	74.85	82.35	71.75	59.35
3/15/2023	36.50	32.00	31.50	105.85	122.00	102.40	58.25	64.45	74.80	82.30	71.70	59.30
3/16/2023	40.60	35.65	35.10	107.75	124.20	104.20	59.15	65.45	76.00	83.05	72.35	59.80
3/17/2023	40.30	35.35	34.80	106.85	123.20	103.35	58.70	64.95	75.40	83.75	72.95	60.30
3/20/2023	43.55	38.45	38.00	104.40	120.40	101.05	63.50	70.25	81.65	84.90	73.95	61.10
3/21/2023	44.15	39.05	38.60	106.20	122.45	102.70	64.40	71.25	82.80	86.20	75.10	62.05
3/22/2023	45.60	40.35	39.90	100.85	116.25	97.50	66.55	73.60	85.55	86.30	75.20	62.15
3/23/2023	45.00	39.75	39.30	95.10	109.60	92.00	65.65	72.60	84.35	85.10	74.15	61.30
3/24/2023	45.05	39.80	39.35	90.30	104.05	87.35	65.75	72.70	84.50	85.05	74.10	61.25
3/27/2023	49.30	43.60	43.15	89.35	102.95	86.40	72.00	79.60	92.50	87.35	76.10	62.90
3/28/2023	49.75	44.05	43.60	88.40	101.85	85.40	73.05	80.75	93.85	88.35	76.90	63.55

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
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Idaho Power/102
Brady/15

Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
3/29/2023	49.25	43.55	43.10	86.45	99.55	83.35	75.55	83.55	97.10	91.30	79.40	65.60
3/30/2023	51.20	45.25	44.80	85.65	98.60	82.60	75.15	83.10	96.55	90.60	78.80	65.10
3/31/2023	50.70	44.80	44.35	84.25	97.00	81.30	74.45	82.30	95.65	89.60	77.95	64.40
4/3/2023	50.65	44.75	44.30	84.10	96.80	81.15	74.35	82.20	95.55	89.50	77.85	64.30
4/4/2023	50.40	44.50	44.05	83.40	96.00	80.50	74.00	81.80	95.10	88.90	77.30	63.85
4/5/2023	51.05	45.05	44.60	84.55	97.35	81.60	74.95	82.85	96.35	89.25	77.55	64.05
4/6/2023	50.40	44.40	43.95	82.55	95.05	79.75	73.90	81.70	95.00	87.80	76.30	63.00
4/10/2023	50.20	44.20	43.75	81.95	94.35	79.20	73.60	81.35	94.60	87.35	75.90	62.70
4/11/2023	49.85	43.90	43.40	80.95	93.20	78.25	73.10	80.75	93.90	86.55	75.20	62.15
4/12/2023	50.50	44.50	44.00	82.85	95.35	80.00	74.10	81.85	95.15	87.65	76.15	62.95
4/13/2023	51.15	45.05	44.55	83.80	96.45	80.95	75.00	82.85	96.30	88.10	76.55	63.25
4/14/2023	50.35	44.30	43.75	81.40	93.70	78.70	73.75	81.50	94.70	87.35	75.90	62.75
4/17/2023	50.30	44.25	43.70	81.25	93.55	78.60	73.70	81.45	94.60	87.25	75.80	62.70
4/18/2023	50.05	44.00	43.45	80.45	92.65	77.85	73.30	81.00	94.05	86.65	75.30	62.30
4/19/2023	50.00	43.95	43.40	80.35	92.55	77.75	73.25	80.95	94.00	86.60	75.25	62.25
4/20/2023	49.75	43.70	43.15	79.55	91.65	77.05	72.85	80.50	93.50	86.05	74.75	61.85
4/21/2023	49.30	43.25	42.70	78.20	90.15	75.80	72.15	79.75	92.60	85.30	74.10	61.30
4/24/2023	48.35	42.35	41.80	76.50	88.20	74.25	70.70	78.15	90.75	83.30	72.40	59.90
4/25/2023	48.70	42.70	42.15	77.55	89.40	75.25	71.25	78.75	91.45	84.05	73.05	60.45
4/26/2023	48.25	42.25	41.70	76.15	87.80	73.95	70.55	77.95	90.50	83.45	72.55	60.05
4/27/2023	49.05	42.90	42.35	76.95	88.70	74.75	71.65	79.20	91.90	84.60	73.55	60.85
4/28/2023	49.45	43.25	42.75	78.10	90.05	75.85	72.25	79.85	92.70	85.00	73.90	61.10
5/1/2023	49.15	42.95	42.45	77.20	89.05	75.05	71.75	79.30	92.05	84.30	73.30	60.60
5/2/2023	49.25	43.05	42.55	77.55	89.45	75.35	71.95	79.50	92.30	86.95	75.60	62.50
5/3/2023	48.75	42.60	42.05	75.85	87.75	74.00	71.20	78.65	91.30	85.85	74.65	61.75
5/4/2023	48.10	42.00	41.45	73.90	85.60	72.25	70.25	77.55	90.05	84.50	73.50	60.80
5/5/2023	48.10	42.00	41.45	73.90	85.60	72.25	70.25	77.55	90.05	84.50	73.50	60.80
5/8/2023	48.90	42.80	42.25	70.55	88.35	74.50	71.50	78.95	91.70	85.70	74.55	61.65
5/9/2023	50.55	44.30	43.75	71.40	90.05	75.95	72.85	80.40	93.40	86.35	75.15	62.10
5/10/2023	50.25	44.05	40.45	70.80	90.50	76.25	74.30	82.00	95.25	87.20	75.85	62.70
5/11/2023	50.30	44.10	37.50	70.60	90.65	76.40	74.35	82.10	95.35	87.40	76.05	62.85

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
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Idaho Power/102
Brady/16

Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
5/12/2023	50.75	44.55	35.95	70.65	92.15	77.65	75.00	82.85	96.20	89.55	77.90	64.35
5/15/2023	50.95	44.70	36.10	70.65	92.75	78.15	75.25	83.15	96.55	89.85	78.15	64.55
5/16/2023	50.70	44.50	34.95	70.15	92.10	77.65	74.90	82.80	96.10	88.95	77.40	63.90
5/17/2023	50.80	44.60	34.80	70.45	92.45	77.95	73.70	81.45	94.55	89.20	77.60	64.05
5/18/2023	50.95	44.75	34.95	70.90	93.00	78.40	73.95	81.70	94.85	89.55	77.90	64.30
5/19/2023	50.85	44.65	34.85	70.55	92.60	78.05	73.75	81.50	94.60	89.25	77.65	64.10
5/22/2023	50.70	44.50	34.65	70.15	92.15	77.70	73.55	81.30	94.35	88.75	77.25	63.75
5/23/2023	50.70	44.50	34.60	70.15	92.15	77.70	73.55	81.30	94.35	88.75	77.25	63.75
5/24/2023	51.95	45.70	35.55	73.60	96.40	81.15	75.35	83.30	96.70	90.65	78.85	65.05
5/25/2023	51.95	45.70	35.55	73.55	96.40	81.15	75.35	83.30	96.70	90.65	78.85	65.05
5/26/2023	51.75	45.50	35.35	73.00	95.70	80.60	75.05	83.00	96.30	90.20	78.50	64.75
5/30/2023	51.70	45.45	35.25	72.80	95.45	80.40	74.95	82.90	96.15	90.05	78.35	64.65
5/31/2023	51.60	45.35	35.10	72.55	95.20	80.20	74.85	82.75	96.00	89.90	78.20	64.55
5/29/2023	51.75	45.50	35.35	73.00	95.70	80.60	75.05	83.00	96.30	90.20	78.50	64.75
6/1/2023	51.10	44.85	34.50	71.15	93.50	78.80	74.10	81.90	95.00	88.85	77.30	63.80
6/2/2023	50.55	44.35	33.90	69.65	91.65	77.30	73.30	81.00	93.95	87.80	76.40	63.05
6/5/2023	50.60	44.40	32.85	69.75	91.75	77.40	73.35	81.05	94.00	87.85	76.45	63.10
6/6/2023	50.25	44.05	32.45	68.70	90.50	76.40	72.80	80.45	93.30	87.40	76.05	62.75
6/7/2023	49.50	43.40	32.10	68.25	89.75	75.75	71.70	79.20	91.90	87.80	76.40	63.05
6/8/2023	49.85	43.70	32.30	68.55	90.20	76.15	72.20	79.75	92.55	88.05	76.55	63.15
6/9/2023	50.05	43.90	32.50	69.05	90.85	76.65	72.45	80.05	92.90	88.30	76.80	63.35
6/12/2023	50.10	43.95	32.55	69.20	91.05	76.80	72.55	80.15	93.00	88.40	76.90	63.40
6/13/2023	50.20	44.05	32.65	69.45	91.35	77.05	72.70	80.30	93.15	88.60	77.05	63.50
6/14/2023	50.20	44.05	32.65	69.45	91.35	77.05	72.70	80.30	93.15	88.60	77.05	63.50
6/15/2023	50.55	44.40	33.00	70.40	92.50	78.00	73.20	80.85	93.80	89.35	77.70	64.00
6/16/2023	50.10	44.00	32.65	69.55	91.40	77.10	72.55	80.15	92.95	88.30	76.80	63.25
6/20/2023	49.80	43.75	32.40	68.80	90.45	76.35	72.15	79.70	92.40	87.45	76.05	62.65
6/21/2023	50.60	44.55	33.20	71.05	93.20	78.60	73.35	81.00	93.95	89.20	77.55	63.85
6/22/2023	50.35	44.30	32.95	70.40	92.40	77.95	73.00	80.60	93.50	88.05	76.55	63.05
6/23/2023	50.30	44.25	32.90	70.25	92.20	77.80	72.90	80.50	93.40	87.90	76.45	62.95
6/26/2023	50.30	44.25	32.90	70.25	92.20	77.80	72.90	80.50	93.40	87.90	76.45	62.95

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
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Idaho Power/102
Brady/17

Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
6/27/2023	49.55	43.55	32.20	68.25	89.75	75.80	71.85	79.35	92.05	86.35	75.15	61.90
6/28/2023	49.55	43.55	32.20	68.25	89.75	75.80	71.85	79.35	92.05	86.35	75.15	61.90
6/29/2023	49.70	43.70	32.35	68.65	90.25	76.20	72.05	79.60	92.30	86.65	75.40	62.10
6/30/2023	49.20	43.25	32.00	67.75	89.10	75.25	71.35	78.80	91.35	85.55	74.45	61.35
7/3/2023	49.20	43.25	32.00	67.75	89.10	75.25	71.35	78.80	91.35	85.55	74.45	61.35
7/5/2023	49.00	43.05	31.80	67.25	88.45	74.75	71.05	78.50	91.00	85.15	74.10	61.05
7/6/2023	48.80	42.85	31.60	66.75	87.85	74.25	70.80	78.20	90.65	84.50	73.55	60.60
7/7/2023	48.55	42.65	31.50	66.75	87.80	74.15	70.40	77.75	90.15	85.20	74.15	61.10
7/10/2023	48.65	42.75	31.60	67.05	88.15	74.45	70.55	77.90	90.35	85.45	74.35	61.25
7/11/2023	48.90	43.00	31.85	67.75	89.00	75.15	70.90	78.30	90.80	85.30	74.25	61.15
7/12/2023	48.35	42.50	31.30	66.25	87.15	73.65	70.10	77.40	89.75	84.15	73.25	60.35
7/13/2023	47.95	42.10	30.90	65.15	85.80	72.55	69.50	76.75	89.00	83.30	72.50	59.75
7/14/2023	48.40	42.55	31.35	66.40	87.35	73.80	70.15	77.50	89.85	84.50	73.55	60.60
7/17/2023	48.45	42.60	31.40	66.55	87.55	73.95	70.25	77.60	89.95	84.60	73.65	60.70
7/18/2023	48.15	42.30	31.10	65.70	86.55	73.10	69.80	77.10	89.40	83.45	72.65	59.90
7/19/2023	48.35	42.50	31.30	66.25	87.20	73.65	70.10	77.40	89.75	85.35	74.30	61.25
7/20/2023	48.20	42.35	31.15	65.80	86.60	73.20	69.85	77.10	89.40	85.00	74.00	61.00
7/21/2023	48.25	42.40	31.20	66.00	86.85	73.40	69.95	77.20	89.55	85.15	74.15	61.10
7/24/2023	48.55	42.65	31.50	66.75	87.80	74.15	70.35	77.65	90.10	85.75	74.65	61.50
7/25/2023	48.60	42.70	31.55	66.90	88.00	74.30	70.45	77.75	90.20	85.90	74.75	61.60
7/26/2023	49.35	43.40	32.25	68.75	90.25	76.15	71.55	79.00	91.65	87.10	75.75	62.40
7/27/2023	50.05	44.10	32.95	69.05	90.60	76.45	72.60	80.15	93.00	87.55	76.15	62.70
7/28/2023	50.70	44.75	33.60	70.90	92.85	78.25	73.55	81.25	94.25	88.30	76.80	63.25
7/31/2023	50.15	44.25	33.05	69.45	91.05	76.80	72.75	80.40	93.25	87.15	75.85	62.45
8/1/2023	49.95	44.10	32.85	68.95	90.45	76.30	72.50	80.10	92.90	86.75	75.55	62.20
8/2/2023	50.15	44.30	33.05	69.05	90.60	76.40	72.80	80.45	93.30	87.40	76.10	62.65
8/3/2023	50.85	44.95	33.70	69.55	91.20	76.90	73.80	81.55	94.60	88.40	76.95	63.35
8/4/2023	50.60	44.70	33.45	68.85	90.35	76.20	73.40	81.15	94.10	86.95	75.70	62.30
8/7/2023	50.40	44.50	33.25	68.25	89.65	75.65	73.10	80.80	93.70	86.50	75.30	62.00
8/8/2023	49.90	44.00	32.75	66.90	88.00	74.30	72.35	80.00	92.75	85.45	74.40	61.30
8/9/2023	50.55	44.65	33.50	65.65	86.45	73.05	73.30	81.05	94.00	86.75	75.55	62.20

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
 April 2020 - March 2021

Idaho Power/102
 Brady/18

Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
8/10/2023	50.90	45.00	33.85	65.90	86.75	73.30	73.80	81.60	94.65	87.25	76.00	62.55
8/11/2023	50.95	45.05	33.90	62.00	82.00	69.40	73.90	81.70	94.75	86.10	75.00	61.75
8/14/2023	50.60	44.75	33.60	61.15	80.95	68.55	73.40	81.15	94.15	85.75	74.70	61.50
8/15/2023	51.65	45.75	34.65	57.50	80.60	68.25	74.95	82.85	96.15	86.65	75.45	62.10
8/16/2023	51.20	45.35	34.20	55.65	78.30	66.40	74.30	82.15	95.30	85.55	74.50	61.30
8/17/2023	50.90	45.05	33.90	54.90	77.35	65.60	73.85	81.65	94.70	84.90	73.95	60.85
8/18/2023	51.25	45.35	34.25	53.85	76.00	64.50	74.35	82.20	95.35	85.00	74.00	60.90

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
April 2020 - March 2021

Idaho Power/102
Brady/19

Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
8/21/2023	51.30	45.40	34.30	54.00	76.20	64.70	74.45	82.30	95.50	85.15	74.10	61.00
8/22/2023	51.85	45.85	34.45	53.65	76.00	64.60	75.25	83.20	96.50	84.05	73.15	60.25
8/23/2023	51.70	45.70	34.30	53.25	75.50	64.20	75.00	82.90	96.15	84.40	73.45	60.50
8/24/2023	50.65	44.75	33.45	51.40	73.10	62.20	73.50	81.20	94.20	84.25	73.30	60.40
8/25/2023	51.45	45.50	34.10	52.65	74.75	63.55	74.70	82.50	95.75	85.40	74.25	61.20
8/28/2023	50.80	44.90	33.45	51.10	72.80	61.95	73.75	81.45	94.55	83.40	72.55	59.80
8/29/2023	50.55	44.65	33.20	49.85	71.25	60.70	73.35	81.00	94.05	83.40	72.60	59.85
8/30/2023	51.30	45.30	33.65	50.45	72.15	61.45	74.45	82.20	95.45	83.20	72.40	59.70
8/31/2023	51.20	45.20	33.55	50.20	71.85	61.20	74.30	82.05	95.25	83.05	72.30	59.60
9/1/2023	51.30	45.30	33.65	50.45	72.15	61.45	74.45	82.20	95.45	83.25	72.50	59.75
9/5/2023	50.25	44.30	32.65	48.00	69.20	58.95	72.95	80.55	93.50	81.20	70.75	58.30
9/6/2023	50.05	44.10	32.45	47.55	68.65	58.50	72.70	80.25	93.15	81.20	70.75	58.30
9/7/2023	49.90	43.95	32.30	47.20	68.25	58.15	72.50	80.00	92.90	81.85	71.30	58.75
9/8/2023	49.60	43.65	32.00	46.50	67.35	57.40	72.05	79.50	92.35	81.25	70.80	58.35
9/11/2023	50.25	44.25	32.60	48.00	69.25	58.95	73.00	80.55	93.55	82.50	71.90	59.25
9/12/2023	50.70	44.65	33.05	49.05	70.55	60.00	73.65	81.25	94.40	82.00	71.45	58.90
9/13/2023	51.25	45.20	33.60	50.40	72.25	61.35	74.45	82.15	95.45	83.15	72.40	59.70
9/14/2023	51.55	45.50	33.90	51.10	73.10	62.05	74.90	82.60	96.00	83.75	72.90	60.10
9/15/2023	51.00	45.00	33.35	49.80	71.50	60.75	74.10	81.75	95.00	82.70	72.00	59.35
9/18/2023	50.00	44.05	32.35	47.40	68.50	58.30	72.65	80.15	93.10	81.30	70.85	58.40
9/19/2023	50.40	44.45	32.75	48.35	69.70	59.25	73.20	80.80	93.85	82.85	72.15	59.45
9/20/2023	51.05	45.05	33.35	49.85	71.55	60.75	74.10	81.80	95.05	84.10	73.25	60.30
9/21/2023	53.35	47.25	35.60	55.30	78.35	66.25	71.75	79.20	92.00	82.40	71.75	59.10
9/22/2023	53.25	47.05	35.10	53.40	76.20	64.55	71.60	79.05	91.80	83.80	72.95	60.05
9/25/2023	52.80	46.60	34.65	52.30	74.80	63.40	70.95	78.35	91.00	84.50	73.55	60.55
9/26/2023	52.45	46.25	34.30	51.50	73.75	62.55	70.50	77.85	90.40	84.00	73.15	60.20
9/27/2023	53.30	47.05	35.15	53.55	76.30	64.60	71.65	79.15	91.90	85.70	74.60	61.40
9/28/2023	53.30	47.05	35.15	53.55	76.30	64.60	71.65	79.15	91.90	85.70	74.60	61.40
9/29/2023	54.05	47.75	35.85	55.30	78.45	66.35	72.65	80.25	93.20	86.80	75.55	62.15
10/2/2023	54.05	47.75	35.85	55.30	78.45	66.35	72.65	80.25	93.20	86.80	75.55	62.15
10/3/2023	54.75	48.45	36.55	56.25	79.60	67.30	73.60	81.30	94.45	87.45	76.10	62.60

Mid-Columbia Heavy Load and Light Load Daily Forward Curves
 April 2020 - March 2021

Idaho Power/102
 Brady/20

Mid-C LL	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
Average	44.28	38.85	34.22	80.53	96.85	84.84	64.26	70.99	82.35	82.77	72.17	59.64
Max LL	54.75	48.45	44.80	107.85	124.20	111.10	75.55	83.55	97.10	91.30	79.40	65.60
Min LL	30.55	25.45	24.75	46.50	67.35	57.40	42.95	47.40	54.70	66.40	58.60	48.90
Spread	24.20	23.00	20.05	61.35	56.85	53.70	32.60	36.15	42.40	24.90	20.80	16.70

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 103

Producer Price Index for Electric Power

October 31, 2023

Mnemonic:	FXPPIFU4.IUSA
Description:	Baseline Scenario (September 2
Source:	U.S. Bureau of Labor Statistics (
Native Frequency:	QUARTERLY
Geography:	United States
Last Updated:	9/11/2023
2020Q1	209.13
2020Q2	212.57
2020Q3	222.63
2020Q4	210.30
2021Q1	214.70
2021Q2	219.90
2021Q3	232.68
2021Q4	223.97
2022Q1	234.02
2022Q2	243.46
2022Q3	263.98
2022Q4	251.47
2023Q1	261.48
2023Q2	263.60
2023Q3	278.31
2023Q4	266.94
2024Q1	267.70
2024Q2	274.44
2024Q3	285.40
2024Q4	274.04
2025Q1	275.29
2025Q2	282.08
2025Q3	292.48
2025Q4	279.91
2026Q1	280.64
2026Q2	287.49
2026Q3	298.32
2026Q4	285.92

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 104

Forward Prices Used for Re-Pricing Purchased Power
and Surplus Sales

October 31, 2023

IDAHO POWER COMPANY
Mid-C Forward Price Curves Discounted for Inflation
Used to Re-Price Purchased Power and Surplus Sales for the October Update (UE 195 & 384 Settlement Methodology)

<u>Line No.</u>		Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
1	Forward Curve Prices												
2	Relevant Quarter	2025 Q2	2025 Q2	2025 Q2	2025 Q3	2025 Q3	2025 Q3	2025 Q4	2025 Q4	2025 Q4	2026 Q1	2026 Q1	2026 Q1
3	Deflator	2.8208	2.8208	2.8208	2.9248	2.9248	2.9248	2.7991	2.7991	2.7991	2.8064	2.8064	2.8064
4	Water Year	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25
5	Relevant Quarter	2024 Q2	2024 Q2	2024 Q2	2024 Q3	2024 Q3	2024 Q3	2024 Q4	2024 Q4	2024 Q4	2025 Q1	2025 Q1	2025 Q1
6	Inflator	2.7444	2.7444	2.7444	2.8540	2.8540	2.8540	2.7404	2.7404	2.7404	2.7529	2.7529	2.7529
7	Average Prices	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
8	Mid-C HL	53.42	50.91	52.51	146.11	170.32	143.88	76.33	84.54	99.15	105.56	90.41	73.67
9	Mid-C LL	44.28	38.85	34.22	80.53	96.85	84.84	64.26	70.99	82.35	82.77	72.17	59.64
10	Inflation Adjusted	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25
11	Mid-C HL	51.98	49.53	51.08	142.58	166.20	140.40	74.73	82.77	97.07	103.55	88.69	72.27
12	Mid-C LL	43.08	37.80	33.29	78.58	94.50	82.79	62.91	69.50	80.63	81.19	70.79	58.51
13	Difference	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
14	Mid-C HL	1.45	1.38	1.42	3.53	4.12	3.48	1.60	1.77	2.08	2.01	1.72	1.40
15	Mid-C LL	1.20	1.05	0.93	1.95	2.34	2.05	1.35	1.49	1.73	1.58	1.38	1.14

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 105

Total Normalized Base Power Supply Expenses for
the 2024 October Update

October 31, 2023

Idaho Power/105
Brady/2

47	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
48	Cost(\$ X 1000)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	Surplus Sales													
49	Energy (MWh)	326,032.7	288,002.0	162,568.9	35,193.5	53,124.5	184,167.7	228,570.6	109,921.8	64,142.7	137,165.0	223,416.5	252,572.4	2,064,878.1
50	Revenue (\$ x 1000)	\$ 15,700.6	\$ 12,547.2	\$ 6,866.3	\$ 4,132.9	\$ 7,514.4	\$ 21,984.2	\$ 15,878.4	\$ 8,524.1	\$ 5,831.2	\$ 12,833.7	\$ 18,101.9	\$ 16,803.4	\$ 146,718.3
51	Surplus Sales - Third Party Transmission Losses (\$ x 1000)	\$ 755.9	\$ 706.2	\$ 863.0	\$ 1,117.3	\$ 1,145.5	\$ 1,002.5	\$ 965.4	\$ 1,130.7	\$ 1,511.9	\$ 1,288.9	\$ 1,266.4	\$ 1,079.2	\$ 12,832.96
52	Lamb Weston Surplus Sales (\$ x 1000)	\$ 227.16	\$ 316.44	\$ 445.95	\$ 400.96	\$ 451.55	\$ 295.66	\$ 313.55	\$ 430.59	\$ 409.59	\$ 305.76	\$ 422.51	\$ 379.88	\$ 4,399.6
53	Net Power Supply Expenses (\$ x 1000)	\$ 3,316.2	\$ 6,697.1	\$ 20,511.7	\$ 53,235.5	\$ 50,046.8	\$ 10,556.7	\$ 11,921.6	\$ 29,380.0	\$ 39,954.4	\$ 26,124.6	\$ 15,448.7	\$ 14,652.4	\$ 281,845.7
54	PURPA (\$ x 1000)	\$ 18,663.1	\$ 21,029.4	\$ 25,750.8	\$ 28,863.9	\$ 28,500.3	\$ 20,754.3	\$ 17,709.1	\$ 17,120.2	\$ 18,207.0	\$ 16,920.7	\$ 20,001.1	\$ 16,805.4	\$ 250,325.4
55	EIM Benefits (\$ x 1000)													\$ 48,437.14
56	Total Net Power Supply Expenses (\$ x 1000)	\$ 21,979.3	\$ 27,726.5	\$ 46,262.5	\$ 82,099.4	\$ 78,547.2	\$ 31,311.0	\$ 29,630.7	\$ 46,500.2	\$ 58,161.5	\$ 43,045.2	\$ 35,449.9	\$ 31,457.8	\$ 483,734.0
57	Sales at Customer Level (In 000s MWH)	1,116.88	1,175.16	1,335.23	1,642.25	1,729.50	1,517.33	1,173.32	1,105.03	1,254.63	1,377.24	1,322.13	1,217.40	15,966.107
58	Lamb Weston kWh Sales (In 000s MWH)	3.87	5.39	7.60	6.83	7.69	5.04	5.34	7.34	6.98	5.21	7.20	6.47	74.959
59	Sales at Customer Level - Net Black Mesa Solar & LW (In 000s MWH)	1,109.92	1,164.11	1,319.60	1,625.31	1,710.33	1,499.00	1,154.99	1,086.73	1,238.41	1,364.94	1,311.19	1,208.11	15,792.635
60	Hours in Month	720	744	720	744	744	720	744	721	744	744	672	743	8,760
61	Unit Cost / MWH (for PCAM)	\$19.80	\$23.82	\$35.06	\$50.51	\$45.93	\$20.89	\$25.65	\$42.79	\$46.96	\$31.54	\$27.04	\$26.04	\$ 30.63

Prices Used in Purchased Power & Surplus Sales Above:

Heavy Load

62	Portion of Purchased Power considered HL Purchases	58.58%	58.77%	67.98%	56.40%	64.29%	61.76%	70.56%	60.49%	59.25%	60.36%	56.26%	48.90%
63	Purchased Power HL Price	\$51.98	\$49.53	\$51.08	\$142.58	\$166.20	\$140.40	\$74.73	\$82.77	\$97.07	\$103.55	\$88.69	\$72.27
64	Portion of Surplus Sales considered HL Surplus Sales	57.04%	49.18%	50.27%	60.71%	65.48%	63.50%	55.45%	60.64%	62.52%	55.33%	57.16%	58.31%
65	Surplus Sales HL Price	\$51.98	\$49.53	\$51.08	\$142.58	\$166.20	\$140.40	\$74.73	\$82.77	\$97.07	\$103.55	\$88.69	\$72.27

Light Load

66	Portion of Purchased Power considered LL Purchases	41.42%	41.23%	32.02%	43.60%	35.71%	38.24%	29.44%	39.51%	40.75%	39.64%	43.74%	51.10%
67	Purchased Power LL Price	\$43.08	\$37.80	\$33.29	\$78.58	\$94.50	\$82.79	\$62.91	\$69.50	\$80.63	\$81.19	\$70.79	\$58.51
68	Portion of Surplus Sales considered LL Surplus Sales	42.96%	50.82%	49.73%	39.29%	34.52%	36.50%	44.55%	39.36%	37.48%	44.67%	42.84%	41.69%
69	Surplus Sales LL Price	\$43.08	\$37.80	\$33.29	\$78.58	\$94.50	\$82.79	\$62.91	\$69.50	\$80.63	\$81.19	\$70.79	\$58.51

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 106

Energy Imbalance Market Benefits

October 31, 2023

IDAHO POWER COMPANY
2024 APCU October Forecast
Energy Imbalance Market Benefit Forecast
Based on September 22 - August 23 Historical Data

		(A)	(B)	(C)	(F)
Year	Month	CAISO Benefit	Zero-cost Hydro Adjustment	Hydro Net (Export)/Import Adjustment	Idaho Power EIM Benefit
2022	September	\$ 6,072,419	\$ 977,710	\$ 1,495,439	\$ 2,473,149
2022	October	\$ 3,919,665	\$ 425,799	\$ 1,306,071	\$ 1,731,870
2022	November	\$ 3,998,746	\$ (1,272,248)	\$ 1,622,279	\$ 350,031
2022	December	\$ 9,260,913	\$ 3,569,294	\$ (1,265,437)	\$ 2,303,857
2023	January	\$ 6,312,513	\$ 705,156	\$ 2,358,528	\$ 3,063,684
2023	February	\$ 3,332,363	\$ 1,601,595	\$ 778,562	\$ 2,380,158
2023	March	\$ 3,674,335	\$ 2,826,150	\$ (9,341)	\$ 2,816,808
2023	April	\$ 8,429,942	\$ 9,384,111	\$ (155,659)	\$ 9,228,452
2023	May	\$ 17,861,967	\$ 17,211,738	\$ 14,615	\$ 17,226,353
2023	June	\$ 5,232,257	\$ 4,032,572	\$ (73,071)	\$ 3,959,501
2023	July	\$ 3,453,712	\$ 2,255,875	\$ (702,437)	\$ 1,553,438
2023	August	\$ 3,024,493	\$ 1,401,903	\$ (52,068)	\$ 1,349,835
Total		\$ 74,573,326	\$ 43,119,656	\$ 5,317,480	\$ 48,437,136

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 107

Energy Imbalance Market Costs

October 31, 2023

**Idaho Power Company
2024 APCU
Oregon Jurisdictional EIM Revenue Requirement**

2023 Calendar Year Revenue Requirement

Capital Investment	\$368,373
ADIT	(\$11,114)
Accumulated Depreciation	(\$12,810)
Amortization of Other Plant	(\$209,621)
Net Rate Base	\$134,829
Return on Rate Base	\$10,459
O&M (On-going)	\$90,770
Depreciation	\$20,720
Taxes	(\$29,332)
Total Operating Expenses	\$82,157
Net-to-Gross Tax Multiplier	1.347
Total Revenue Requirement	\$124,718

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 108

Year-Over-Year Differences in Modeled Normalized
Power Supply Expenses

October 31, 2023

IDAHO POWER COMPANY
YEAR OVER YEAR DIFFERENCES IN AURORA DEVELOPED NPSE
2024 OCTOBER UPDATE

AURORA DEVELOPED NPSE RESULTS BEFORE MARKET ENERGY RE-PRICING				REPRICED USING FORWARD MARKET PRICES					DIFFERENCES			
GENERATION				GENERATION					GENERATION			
Line No.	Resource Type	A 2023 October Update	B 2024 October Update	Resource Type	C 2023 October Update	D	E 2024 October Update	F	G (B-A)	H (E-C)	I (C-A)	J (E-B)
1	Hydro (MWh)	8,373,292	8,224,002	Hydro (MWh)	8,373,292	49%	8,224,002	48%	(149,290)	(149,290)	-	-
2	Coal (MWh)	2,457,884	2,083,094	Coal (MWh)	2,457,884	14%	2,083,094	12%	(374,789)	(374,789)	-	-
3	Natural Gas (MWh)	1,125,145	3,036,709	Natural Gas (MWh)	1,125,145	7%	3,036,709	18%	1,911,565	1,911,565	-	-
4	Market Purchased Power (MWh)	2,194,867	1,247,996	Market Purchased Power (MWh)	2,194,867	13%	1,247,996	7%	(946,871)	(946,871)	-	-
5	Purchased Power Agreements (MWh)	983,035	1,677,361	Purchased Power Agreements (MWh)	983,035	6%	1,677,361	10%	694,326	694,326	-	-
6	Storage (MWh)	(27,539)	(64,770)	Storage (MWh)	(27,539)	0%	(64,770)	0%	(37,232)	(37,232)	-	-
7	Other*	-	18,020	Other*	-	-	18,020	0%	18,020	18,020	-	-
8	PURPA (MWh)	3,179,923	3,106,875	PURPA (MWh)	3,179,923	19%	3,106,875	18%	(73,048)	(73,048)	-	-
9	Surplus Sales (MWh)	1,098,058	2,064,878	Surplus Sales (MWh)	1,098,058	-6%	2,064,878	-12%	966,820	966,820	-	-
10	System Generation (MWh)	18,286,606	19,329,287	System Generation (MWh)	18,286,606	-	19,329,287	-	75,861	75,861	-	-
11	System Load (MWh)	17,188,548	17,264,409	System Load (MWh)	17,188,548	100%	17,264,409	100%	75,861	75,861	-	-
12	System Load (aMW)	1,957	1,971	System Load (aMW)	1,957	-	1,971	-	14	14	-	-
NET POWER SUPPLY EXPENSES				NET POWER SUPPLY EXPENSES					NET POWER SUPPLY EXPENSES			
Line No.	Resource Type	A 2023 October Update	B 2024 October Update	Resource Type	C 2023 October Update	D	E 2024 October Update	F	G (B-A)	H (E-C)	I (C-A)	J (E-B)
13	Hydro (\$ x 1000)	\$ -	\$ -	Hydro (\$ x 1000)	\$ -	-	\$ -	-	\$ -	\$ -	\$ -	\$ -
14	Coal (\$ x 1000)	\$ 82,110.1	\$ 84,642.4	Coal (\$ x 1000)	\$ 82,110.1	17%	\$ 84,642.4	17%	\$ 2,532.3	\$ 2,532.3	\$ -	\$ -
15	Natural Gas (\$ x 1000)	\$ 53,345.4	\$ 163,430.7	Natural Gas (\$ x 1000)	\$ 53,345.4	11%	\$ 163,430.7	34%	\$ 110,085.3	\$ 110,085.3	\$ -	\$ -
16	Market Purchased Power (\$ x 1000)	\$ 88,294.0	\$ 50,738.2	Market Purchased Power (\$ x 1000)	\$ 134,158.6	28%	\$ 117,331.0	24%	\$ (37,555.8)	\$ (16,827.6)	\$ 45,864.7	\$ 66,593
17	Purchased Power Agreements (\$ x 1000)	\$ 55,740.2	\$ 80,392.5	Purchased Power Agreements (\$ x 1000)	\$ 55,740.2	12%	\$ 80,392.5	17%	\$ 24,652.3	\$ 24,652.3	\$ -	\$ -
18	Storage (\$ x 1000)	\$ -	\$ -	Storage (\$ x 1000)	\$ -	0%	\$ -	0%	\$ -	\$ -	\$ -	\$ -
19	PURPA (\$ x 1000)	\$ 240,220.1	\$ 250,325.4	PURPA (\$ x 1000)	\$ 240,220.1	50%	\$ 250,325.4	52%	\$ 10,105.3	\$ 10,105.3	\$ -	\$ -
20	Surplus Sales (\$ x 1000)	\$ (39,043.8)	\$ (106,627.6)	Surplus Sales (\$ x 1000)	\$ (49,544.5)	-10%	\$ (163,950.9)	-34%	\$ (67,583.8)	\$ (114,406.4)	\$ (10,500.8)	\$ (57,323)
21	EIM Benefits	\$ (34,739.0)	\$ (48,437.1)	EIM Benefits	\$ (34,739.0)	-7%	\$ (48,437.1)	-10%	\$ (13,698.1)	\$ (13,698.1)	\$ -	\$ -
22	Total System (\$ x 1000)	\$ 445,927.0	\$ 474,464.5	Total System (\$ x 1000)	\$ 481,290.9	100%	\$ 483,734.0	100%	\$ 28,537.5	\$ 2,443.1	\$ 35,363.9	\$ 9,269.4

*Includes Demand Response and Oregon Community Solar

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 109

Revenue Spread

October 31, 2023

Idaho Power Company
Stipulated Revenue Spread
2024 October Update

Line No.	2024 October Update Oregon Jurisdictional Share of Base NPSE = \$30.63/MWh x 681,006.975	
1	MWhs =	\$20,859,244
2	Oregon Allocated EIM Costs	\$124,718
3	Proposed October Update APCU Revenue Requirement	\$20,983,961

	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)	
4	April 2024 - March 2025 Generation Level Normalized Sales (kWh)	723,359,039	207,731,587	108,327	21,705,069	121,161,337	15,526,472	3,235,789	405,130	182,431,542	98,906,339	71,620,864	5,786.71	496,109.60	24,685.89
5	Class Share of April 2024 - March 2025 Generation Level Normalized Sales (kWh)	100%	28.72%	0.01%	3.00%	16.75%	2.15%	0.45%	0.06%	25.22%	13.67%	9.90%	0.00%	0.07%	0.00%
6	2023 October Update Class Allocated Base NPSE	\$ 20,983,961	\$ 6,026,097	\$ 3,142	\$ 629,644	\$ 3,514,776	\$ 450,408	\$ 93,867	\$ 11,752	\$ 5,292,166	\$ 2,869,179	\$ 2,077,654	\$ 168	\$ 14,392	\$ 716
7	June 2024 - May 2025 Loss-Adjusted Normalized Sales (kWh)	682,039,038	193,137,625	100,679	20,224,490	112,965,508	14,785,591	3,144,596	377,216	173,740,839	96,233,282	66,838,913	5,388	461,927	22,985
8	Proposed APCU Rates for 2024 October Update (\$/kWh)	0.030767	0.031201	0.031213	0.031133	0.031114	0.030463	0.029850	0.031156	0.030460	0.029815	0.031084	0.031156	0.031156	0.031156
9	Proposed October Update APCU Revenue Requirement	\$20,983,961	\$6,026,097	\$ 3,142	\$629,644	\$3,514,776	\$450,408	\$93,867	\$11,752	\$5,292,166	\$2,869,179	\$2,077,654	\$168	\$14,392	\$716
10	APCU Rates for 2023 October Update (\$/kWh) - Order No. 23-184	0.030889	0.031490	0.031490	0.031451	0.031449	0.030454	0.029708	0.031490	0.030420	0.029651	0.031449	0.031483	0.031490	0.031488
11	June 2024 - May 2025 Loss-Adjusted Normalized Sales (kWh)	682,039,038	193,137,625	100,679	20,224,490	112,965,508	14,785,591	3,144,596	377,216	173,740,839	96,233,282	66,838,913	5,388	461,927	22,985
12	Base NPSE Recovered under Current APCU Rates	\$21,085,517	\$6,081,860	\$ 3,170	\$636,088	\$3,552,662	\$450,278	\$93,421	\$11,878	\$5,285,268	\$2,853,420	\$2,102,032	\$170	\$14,546	\$724

Idaho Power/110
Witness: Jessica G. Brady

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 110

Revenue Impact

October 31, 2023

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
APCU October Update
Effective June 1, 2024

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 2 82% Cap	Revenue Requirement Shortfall
<u>Uniform Tariff Rates:</u>													
1	Residential Service	1	13,812	193,137,625	\$12,551,127	6,081,860	\$18,632,987	\$6,026,097	\$18,577,224	(\$55,764)	(0.30)%	(\$55,764)	\$0
2	Residential Service - Time-of-Day Pilot	5	4	100,679	\$6,008	3,170	\$9,178	\$3,142	\$9,150	(\$28)	(0.30)%	(\$28)	\$0
3	Small General Service	7	2,745	20,224,490	\$1,540,879	636,088	\$2,176,966	\$629,644	\$2,170,522	(\$6,444)	(0.30)%	(\$6,444)	\$0
4	Large General Secondary	9S	970	112,965,508	\$5,593,473	3,552,662	\$9,146,135	\$3,514,776	\$9,108,248	(\$37,886)	(0.41)%	(\$37,886)	\$0
5	Large General Primary	9P	9	14,785,591	\$637,024	450,278	\$1,087,302	\$450,408	\$1,087,432	\$131	0.01%	\$131	\$0
6	Large General Transmission	9T	1	3,144,596	\$110,025	93,421	\$203,446	\$93,867	\$203,893	\$446	0.22%	\$446	\$0
8	Dusk to Dawn Lighting	15	0	377,216	\$97,454	11,878	\$109,332	\$11,752	\$109,206	(\$126)	(0.12)%	(\$126)	\$0
9	Large Power Primary	19P	5	173,740,839	\$5,898,626	5,285,268	\$11,183,893	\$5,292,166	\$11,190,792	\$6,899	0.06%	\$6,899	\$0
10	Large Power Transmission	19T	1	96,233,282	\$3,384,930	2,853,420	\$6,238,350	\$2,869,179	\$6,254,109	\$15,759	0.25%	\$15,759	\$0
11	Agricultural Irrigation Service	24	2,309	66,838,913	\$4,600,790	2,102,032	\$6,702,822	\$2,077,654	\$6,678,444	(\$24,379)	(0.36)%	(\$24,379)	\$0
12	Unmetered General Service	40	2	5,388	\$186	170	\$356	\$168	\$354	(\$2)	(0.50)%	(\$2)	\$0
13	Street Lighting	41	27	461,927	\$132,549	14,546	\$147,095	\$14,392	\$146,941	(\$154)	(0.10)%	(\$154)	\$0
14	Traffic Control Lighting	42	11	22,985	\$1,643	724	\$2,367	\$716	\$2,360	(\$8)	(0.32)%	(\$8)	\$0
15	Total Uniform Tariffs		19,896	682,039,038	\$4,554,714	21,085,517	\$5,640,231	\$20,983,961	\$5,538,675	(\$101,556)	(0.18)%	(\$101,556)	0
16	Total Oregon Retail Sales		19,896	682,039,038	\$4,554,714	\$21,085,517	\$5,640,231	\$20,983,961	\$5,538,675	(\$101,556)	(0.18)%		

(1) Updated June 2024-May 2025 Test Year

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document on the parties to Docket UE 414, Idaho Power's 2024 Annual Power Cost Update, on the following named person(s) on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below.

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DATED: October 31, 2023

/s/ Cole Albee

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