Oregon
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January 31, 2024

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION ATTENTION: FILING CENTER
PO BOX: 1088
SALEM OR 97308-1088

RE: Docket No. UE 425 – In the Matter of IDAHO POWER COMPANY, 2024 Annual Power Cost Update.

Attached for Staff Opening filing are the following exhibits:

Anna Kim: Exh 100-102 Conf
Julie: Exh 200-203 and one electronic attachment
Dean Ratliff: Exh 300-302 Conf and one CONF electronic attachment
Rose Pileggi: Exh 400-401
David Abraham: Exh 500-501

Certificate of Service and Service List are included with this filing.

/s/ Kay Barnes
Oregon Public Utility Commission
(971) 375-5079
Kay.barnes@puc.oregon.gov

UE 425 SERVICE LIST

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CERTIFICATE OF SERVICE

UE 425

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180 to the following parties or attorneys of parties.

Dated this 31st day of January, 2024 at Salem, Oregon

Kay Barnes

____

Kay Barnes
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
Telephone: (971) 375-5079

CASE: UE 425
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION OF OREGON

CONFIDENTIAL STAFF EXHIBIT 100

Opening Testimony

January 31, 2024

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

A. My name is Anna Kim. I am the Energy Costs Section Manager employed in the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. I provide a summary of Idaho Power Company's (Idaho Power, IPC, or the Company) 2024 Annual Power Cost Update filing (APCU), and address Idaho Power's compliance with past orders and hydro modeling.

Q. Did you prepare any exhibits for this docket?

A. Yes. In addition to this testimony and witness qualification statement, I also prepared Exhibit Staff/102, a response to a Staff data request.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. What other testimony is provided in this filing?

A. In addition to my testimony, additional testimony is presented in the following order:

- Staff witness Julie Dyck discusses the Western Energy Imbalance Market (WEIM), natural gas costs, and Aurora modeling in Staff/200.
- Staff witness Dean Ratliff discusses new resources, Public Utility Regulatory Policy Act (PURPA), and demand response in Staff/300.
- Staff witness Rose Pileggi discusses Bridger Unit 1 Unit and 2 conversions in Staff/400.
- Staff witnesses David Abraham and Bret Stevens discuss net power supply expense (NPSE), revenue requirements, system load, rate spread, and the jurisdictional allocation of net power costs in Staff/500.

Q. Are there adjustments that Staff is recommending?

A. Yes. While Staff's review is ongoing, Staff's initial recommendations include applying a 61 percent growth factor to EIM benefits in the March Forecast and future APCUs that would result in a system-wide downward adjustment of $2,740,735 as outlined in Staff/200 and a downward system-level adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in PURPA expenses as outlined in Staff/300.

OVERVIEW

Q. Please summarize the Annual Power Cost Update (APCU).

A. The APCU provides Idaho Power a mechanism to have timely recovery of its net power supply expense which is the Company's forecast of power costs. The APCU is a two-part filing that was implemented to adjust rates on an annual basis to capture variability in power supply expenses that occur from a predominately hydro-based generation.[1] The APCU's two components are the October Update and March Forecast. The October Update is based on the Company's modeling of power costs and establishes a "baseline" or "normal" forecast based on a historic record of hydrologic conditions that impact hydro resources. The March Forecast estimates the company's net power supply expenses with updated actual hydrologic conditions. Both the October Update and March Forecast use a forecasted future Test Year of April 1 to March 31. The APCU mechanism allows for the rates from the October Update and March Forecast to become effective on June 1 of each year.[2]

Q. Please summarize the revenue impact of Idaho Power's 2023 October Update to the APCU filing.

A. The Company filed on October 31, 2023, its NPSE as well as the determination of the marginal cost of energy for the Test Year. If approved as filed, the 2024 October Update will result in a revenue decrease for Oregon customers of $101,556, or 0.48 percent, to become effective June 1, 2024. However as

1 Order No. 08-238.
2 Order No. 16-206.

noted earlier, Idaho Power will update its information again in March and therefore likely have a revised request even if no other party had any recommended changes. Staff's opening testimony relates to the Company's October Update only. Staff will conduct further analysis once the March Forecast has been filed and reviewed.

Q. What is the Oregon-allocated share of NPSE?

A. Based on the Company's forecast, the Company calculates the Oregon jurisdictional share of NPSE as $20.86 million.[3] As I will mention shortly, this calculation will be discussed further in Staff/500 and in UE 426. Staff seeks a consistent methodology across the GRC and power cost dockets.

Q. How is the Oregon allocation calculated?

A. The Company calculates the Oregon jurisdictional share of NPSE by multiplying the Oregon jurisdictional loss-adjusted normalized sales for the April 2024 through March 2025 test period by the $/MWh system NPSE. There are also additional EIM costs added to this number. In this filing, the Company estimates the Oregon jurisdictional share of the base NPSE calculation is $30.63/MWh x 681,006.975 MWhs = $20,859,244 plus an additional $124,718 in EIM costs for a total of $20,983,961.

Q. How have the components of the Oregon allocation calculated changed?

A. Between the 2023 October Update and the 2024 October Update, the $/MWh estimated system NPSE decreased by 3.16 percent, expected Oregon sales

[3] Idaho Power/100 Brady/32-33.

decreased by 3.24 percent, and EIM costs increased by 8.76 percent, leading to a 6.22 percent reduction in revenue requirement. Oregon costs will be lower on a per-unit basis and overall. Revenue requirement will be discussed further in Staff/500.

Q. Does Staff have positions that impact this calculation?

A. Yes. Staff witness David Abraham discusses the Company's load forecasting methodology, which is used to forecast sales, a component of the Oregon allocation calculation. Please see Exhibit Staff/500 for further discussion on this topic. Staff will discuss this topic further in UE 426, Idaho Power's General Rate Case (GRC). Staff recommends that any changes made to the load forecast methodology in the GRC should also be applied to the APCU. If adopted, forecast changes will result in a change in the forecast for Oregon load and impact the Oregon allocation.

Q. What is the Company's forecast for generation and load?

A. The Company forecasts 19.33 million MWh in generation on a system-wide basis, which includes 2.06 million MWh in surplus sales and meeting a system load of 17.26 million.[4]

Q. What is the Company's forecasted resource mix?

A. Figure 1 below shows the source of energy forecast in this year's October Update using the Aurora modeling determination of normalized NPSE for the Test Year in Exhibit Idaho Power/108 and compared to the previous year's October Update. This chart does not include system sales or storage. Hydro

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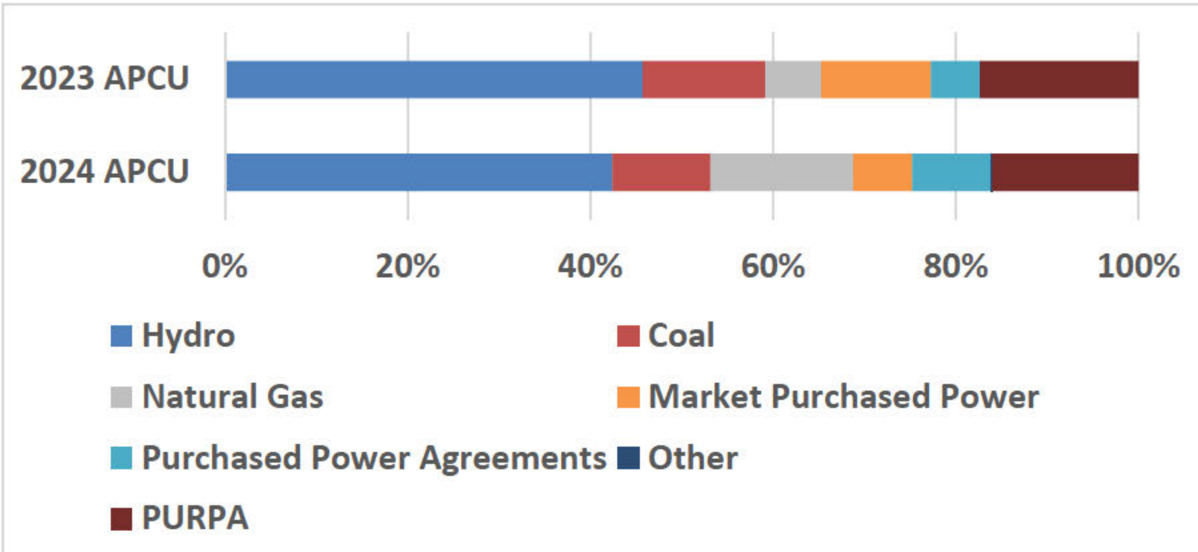
4 Exhibit Idaho Power/108.

makes up the largest portion of the total resource mix followed by PURPA resources, gas, and coal.

FIGURE 1: SYSTEM GENERATION COMPARISON BY FUEL TYPE[5]

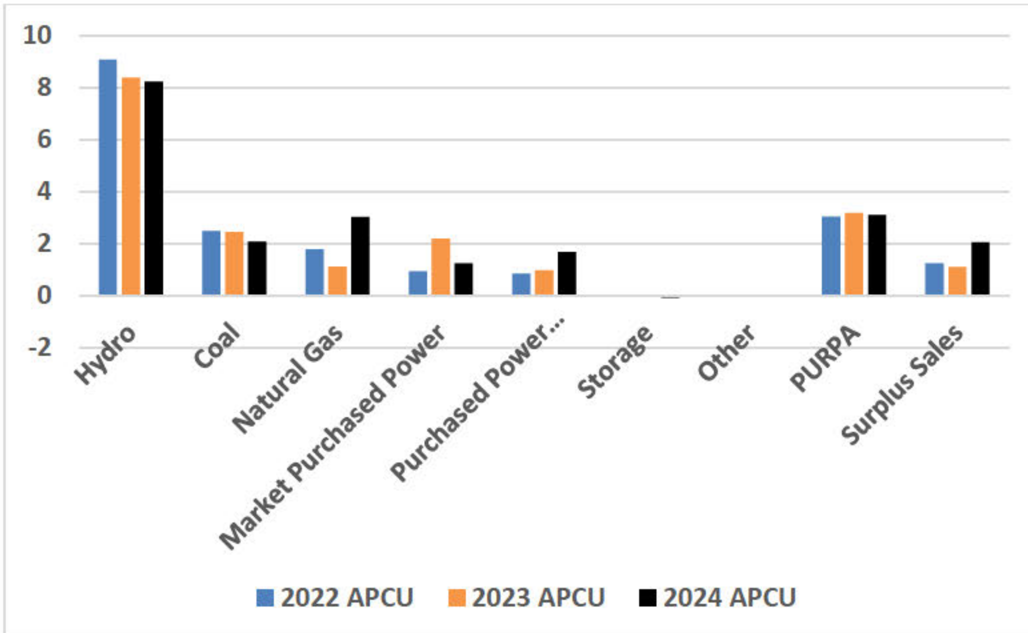


Q. How does this year's resource mix compare to previous years?

A. Figure 1 also illustrates the shift in resource mix between this year and last year. The forecast of natural gas generation is increasing while coal and market purchases are decreasing. Figure 2 shows the relative change in the resource mix from the October Updates in the 2022 APCU, the 2023 APCU, and the 2024 APCU. In the last October Update, natural gas generation was down, and market purchases were up. In this October Update, market purchases drop back down and natural gas generation increases along with surplus sales. Coal is also higher last year and lower this year.

5 In addition, 27,538 MWh is deducted to arrive at a generation total of 18.29 million MWh. This is for the storage for three batteries which are scheduled to come online June 2023 (40 MW Blake Mesa Battery, 80 MW Grid Battery, an 11 MW Grid Battery).

FIGURE 2: RESOURCE CHANGES ACROSS OCTOBER UPDATES



Q. Why is gas generation increasing while coal generation is decreasing?

A. The switch in fuel mix from coal to gas is primarily attributable to converting Bridger Units 1 and 2 from coal generation to gas generation. These coal-generation resources were taken offline for the conversion and are expected to come back online as gas plants in the summer of 2024. The Company also notes that because the forecast for the price of gas is 33 percent lower than the gas price forecast at this time last year, the Company anticipates increasing opportunities to sell gas-generated energy in the market.[6] While gas generation tends to be more expensive than coal generation, the decrease in cheaper coal generation is offset with a higher volume of sales from natural gas-generated energy.

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[6] Idaho Power/100 Brady/12.

Q. What is driving the overall decrease in NPSE from the previous year?

A. The main driver of the reduction in expected rates from NPSE is increased sales of natural gas-generated energy. Figure 3 illustrates how surplus sales will lower costs by an additional $114.4 million. Market purchases will also decline by $16.8 million. The change in market purchases in sales will more than offsets a $110.1 million increase in natural gas generation costs.[7]

FIGURE 3: DIFFERENCE IN NET POWER SUPPLY EXPENSES BETWEEN OCTOBER 2023 UPDATE AND OCTOBER 2024 UPDATE[8]

Q. Does the Boardman-to-Hemingway (B2H) transmission project impact this APCU?

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7 Exhibit Idaho Power/108.

8 Exhibit Idaho Power/108 after repricing.

A. No. based on the Company's most recent Integrated Resource Plan (IRP) filing, B2H is scheduled to come online in 2026 and will not be available during the 2024 APCU time period.[9]

[9] LC 84, Idaho Power's 2023 Integrated Resource Plan, p. 132. In the Preferred Portfolio, Idaho Power selected an online date of July 2026. The Company tested an alternative date of November 2026 which was identified as higher cost by the Company's modeling.

ISSUE 1. COMPLIANCE WITH PAST ORDERS

Q. What are the requirements of Order No. 08-238 that are relevant the October Update?

A. Order No. 08-238 initially established the two-part APCU process where an October Update is filed with an effective date of June 1 of the following year. The update would be based off a test period of April through March with a normalized look at the NPSE using the Company's Aurora output which is then re-priced using Mid-C prices. The October Update includes updates to the following variables:

a. Fuel prices and transportation costs
b. Wheeling expenses
c. Planned outages and forced outage rates
d. Heat rates
e. Forecast of normalized load and normalized sales
f. Contracts for wholesale power and power purchases and sales
g. Forward price curve
h. Public Utility Regulatory Policies Act of 1978 ("PURPA") contract expenses
i. The Oregon state allocation factor
j. Updates to plant capabilities and acquisitions or changes to resources effective for the Test Period.

Order No 08-238 has similar requirements for the March Forecast reflecting current hydro conditions.

Q. Did Idaho Power comply with Order No. 08-238?

A. Yes. The Company has submitted the October Update on October 31, 2023, consistent with Order No. 08-238.

Q. What are the requirements of Order No. 23-184 from the last APCU?

A. Order No. 23-184 adopts the stipulation agreement between the stipulating parties Idaho Power, Citizens' Utility Board (CUB), and Staff and requires that tariff compliance filings are submitted as outlined in the stipulation. The stipulation itself adjusts the 2023 APCU to include $1.55 million in EIM benefits, reduce Oregon-allocated PURPA expenses by $316,000, a total revenue requirement increase of $7.69 million, and rates would go into effect on June 1, 2023. There were no agreements that impacted future APCUs.

Q. Did Idaho Power comply with Order No. 23-184.

A. Yes. The Company submitted compliance filings on May 31, 2023, consistent with the stipulation.

Q. Does Staff have any recommendations on the topic of compliance?

A. Not at this time. Staff will similarly review the Company's compliance for the March Forecast.

ISSUE 2. HYDRO MODELING

Q. How does Idaho Power generate hydro data inputs for the APCU?

A. Idaho Power uses the software RiverWare which models river and reservoir conditions. This software forecasts what hydro is available for dispatch using historic data and recent observations of various hydrologic conditions that impact the Company's hydro resources. Hydro availability is used as an input for the Aurora model which is the primary software Idaho Power uses to forecast the APCU. The RiverWare model for the Snake River came from the U.S. Bureau of Reclamation and Idaho Power worked with RiverWare developers to create a custom model for the Hells Canyon Complex.[10]

Q. How long has the Company used RiverWare as part of the APCU?

A. Idaho Power first implemented the Riverware software for the October 2022 forecast of the APCU. RiverWare replaced the existing legacy system used to model the Company's hydro resources.[11]

Q. Please summarize Staff's findings from the previous APCU.

A. In the 2023 APCU, Staff did not recommend any changes or adjustments to the Company's use of RiverWare or to the Company's hydro modeling. The initial implementation used 67 hydro years of historic data from 1951–2017, which is an expansion from the 37-year period (1981–2017) used in the 2022 APCU[12] and the 2024 APCU. In the 2023 APCU, Staff reviewed the newly introduced RiverWare software and inputs used for the October 2022 forecast as well as

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[10] Idaho Power/100, Brady/15.
[11] Idaho Power/100, Brady/15.
[12] Idaho Power's response to Staff DR 52.

the March 2023 forecast. Staff referenced this change in Opening Testimony without any recommendations for adjustments.[13]

Q. Is the Company proposing changes to hydro modeling from what was used last year?

A. Yes. For the 2024 APCU, in addition to routine updates based on current hydrologic conditions, the Company is using a shorter Period of Record ("POR") of historic data covering 37 water years from 1981 to 2017. The Company notes that this range is consistent with the Company's modeling in the 2023 Integrated Resource Plan (IRP).[14]

Q. Why did the Company change the POR?

A. In response to Staff Data Request No. 52, the Company indicated it chose the period 1981–2017 for the POR in this APCU as it reflects a more accurate representation of current hydrologic operating conditions for the purposes of modeling the 20-year time horizon of the IRP. This time period is consistent with Idaho Power's weather calibration modeling. Idaho Power also notes that the chosen POR ends in 2017 because updates to modeling data are conducted infrequently and the 2017 water year is the most recent data currently available in RiverWare. This modeling relies on U.S. Bureau of Reclamation updates which are typically conducted once every ten years. Other organizations such as the Bonneville Power Administration are using a

[13] UE 414, Staff/100, Jent/25-26.
[14] Idaho Power's response to Staff DR 52.

30-year POR rather than the 90-year historical record to reflect recent climate and operating conditions.

Q. Does Staff have any recommendations at this time?

A. Not at this time. Staff supports the Company's efforts to modernize the model and will continue to monitor the predictive power of the new software.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 425
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

January 31, 2024

NAME:	Anna Kim
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Energy Costs Section Manager Rates, Safety and Utility Performance Program
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Master of Science, Economics Portland State University, Portland, OR Master of Environmental Studies, The Evergreen State College, Olympia, WA Bachelor of Arts, Environmental Science, University of California, Berkeley, CA
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission (OPUC) since July 2018 originally in the Energy Resources and Planning Division principally as the Staff liaison with the Energy Trust and then as Energy Costs Section Manager starting May 2023. My responsibilities include analyzing, working with Staff assigned, leading and managing energy cost dockets. Prior to working for the Commission, I worked for Seattle City Light as a power resource planner developing integrated resource plans. I also worked for five years as an evaluation consultant which involved evaluating energy efficiency and demand response pilots and programs and market research.

CASE: UE 425
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

January 31, 2024

Topic or Keyword: hydro

STAFF'S DATA REQUEST NO. 52:

Please provide a narrative description of how the hydrology period of record was selected and why it is changing.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 52:

The hydrology period of record has not changed from the 2022 Annual Power Cost Update ("APCU") filing.

A 30-year period is common in hydrometeorological settings for summarizing historical statistics. For Idaho Power's Integrated Resource Plan ("IRP") modeling, which is the same modeling that feeds into the APCU filing, the intent is to use a representative range of hydrologic conditions to generate a distribution of potential hydropower outcomes in each year over the 20-year IRP horizon. For this purpose, Idaho Power is not specifically constrained to use a 30-year record. The intent is to use a record of sufficient length to capture hydrologic variability.

1981 is used as the beginning year for several reasons. First, consistent with updates made by Bonneville Power Administration ("BPA") for their long term hydrogeneration studies[1], a more recent period better reflects climate change impacts to hydrologic processes and water supplies. BPA found that the recent 30-year record better follows projected trends in future stream flows as modeled in the River Management Joint Operating Committee Part I and II studies[2]. Idaho Power believes that the period starting in 1981 and extending through 2017 is representative of current hydrology and is consistent with the projected hydrologic response from climate change.

A beginning year of 1981 is also related to Idaho Power's use of hydrologic models to simulate the effects of weather modification on the historically observed hydrology. These models are calibrated focusing on their performance from 1981 through approximately 2019. Since the hydrologic models are calibrated back to 1981, Idaho Power has confidence that simulating weather modification impacts to water supplies using historical hydrology from those years provides a well-calibrated hydrologic response and simulation of additional water supply resulting from weather modification.

The ending year of 2017 is related to the RiverWare planning model that Idaho Power uses to simulate the hydrogeneration in each year of the hydrology period of record. The RiverWare model is present-conditioned through water year 2018 (September 30, 2018). This means that the model is representative of reservoir operations, irrigation patterns, and groundwater conditions at the end of the 2018 water year, such that simulated hydrogeneration in a historical year of the period of record is still representative of how the system as it is operated today would respond to a given hydrologic condition. Because it is a significant effort to present-condition planning models, this type of update is conducted infrequently. The U.S. Bureau of Reclamation, which originally developed the RiverWare model that Idaho Power adapted for the

[1] https://www.bpa.gov/energy-and-services/power/climate-change-fcrps
[2] https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf, https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-ll.PDF

IRP, only present-conditions models approximately every 10 years. The period of record ending with 2017 is a result of this infrequent update.

Ultimately, Idaho Power uses the 37-year period of record to balance having enough historical hydrologic variability with the trends of climate change while also targeting optimum hydrologic modeling performance.

CASE: UE 425
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

January 31, 2023

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

A. My name is Julie Dyck. I am a Senior Economist/Utility Analyst employed in the Energy Costs Section of the Rates, Safety and Utility Performance (RSUP) Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. These can be found in my witness qualification statement, which is Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. My testimony details the recommendations by Staff regarding the Western Energy Imbalance Market (EIM) and touches on natural gas prices and the use of AURORA.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff 201, Exhibit Staff 202 comprised of Idaho Power responses to Staff data requests and Exhibit Staff/203, which is a Staff workpaper.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. WESTERN ENERGY IMBALANCE MARKET (WEIM OR EIM)

Q. What is the EIM?

A. The EIM is a voluntary, balancing (generation and load) energy market that was established in 2014 by the California Independent System Operator (CAISO); there are 22 market participants, and it represents nearly 80 percent of the demand for electricity in the western wholesale market interconnection. Utilities participating in EIM begin each hour with their forecast of load and generation balanced. This plan for running the system is referred to as the "base schedule." The utilities provide generation bids to the market for each generator unit, reflecting at what price they are willing to increase or decrease generation from their base schedule. The CAISO uses software to optimize generator dispatch within and between Balancing Authority Areas (BAAs). Sub-hourly transactions (every 5 and 15 minutes) serve real-time customer demand and facilitate transfer of excess energy generated in one area to another where it is needed. The EIM is not a capacity market and thus, participants must enter each operating hour with a balanced load and resource portfolio.[1] Idaho Power joined in April 2018.

Q. Are there costs associated with the EIM included in the APCU?

A. Yes. However, EIM costs are included in the Test Year for the Company's GRC. As updated rates from the GRC will take effect October 15, 2024, the Company will update its EIM costs included in the APCU for the time period

[1] Staff/202, Idaho Power's response to DR 19 (pdf).

between April 1 – October 14. EIM costs will no longer be included in the APCUs after this year.[2]

Q. What are the benefits to being a participant in the EIM?

A. Benefits can take the form of cost savings, margin, or a combination of the two. The primary benefit of the EIM is that it allows participants to obtain least-cost energy to serve load. Idaho Power has the ability to have the CAISO schedule to export and import in near real time with other EIM participants to respond to intra-hour imbalances. IPC imports power from the EIM when prices are low to avoid production costs on more expensive generating units and alternatively, IPC can export power to the EIM, earning net revenues when EIM prices are higher than their own production costs.

Other benefits include the economic efficiency of an automated dispatch model for both generation and transmission line congestion, savings due to diversity of loads and variability of resources within the expanded footprint, lower flexible ramping requirements, reduced operational risk due to enhanced system reliability, and ability to better support the integration of renewable resources.

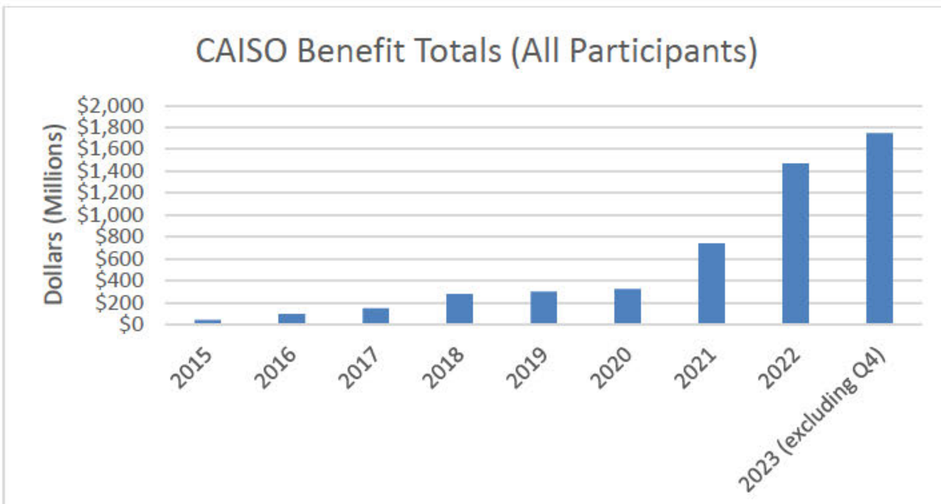
Q. How does the CAISO estimate the benefits?

A. The CAISO quantifies EIM benefits as the difference between the Company's costs and revenues participating in EIM and an estimate of what the Company's costs and revenues would have been absent EIM (the counterfactual dispatch). In estimating the counterfactual dispatch, the EIM

[2] This was included in a document shared via email correspondence by IPC on January 8, 2024.

assumes the generation bids submitted reflect the Company's true cost of generation. For each five-minute interval, the EIM benefit for a BAA = counterfactual dispatch cost – (EIM dispatch cost + transfer cost + flex ramp transfer cost) + GHG revenue – GHG cost. The five-minute level EIM benefits are then aggregated each month with a multiplier of 1/12 to convert ($/5 min) to a dollar amount.[3]

FIGURE 1: TOTAL EIM BENEFITS (ALL PARTICIPANTS)



Q. What issues does the Company have with CAISO's way of calculating benefits?

A. Idaho Power states that the assumption that a bid price is the true cost of generation is not accurate with hydro generation. In its testimony, IPC discusses how bids for hydropower resources are based on operational need rather than actual dispatch cost.[4] In addition, Idaho Power is also

[3] EIM-BenefitMethodology.pdf (westerneim.com).
[4] Idaho Power/100, Brady26.

aware that other utilities are performing their own forecast or calculation but does not know the details behind other methodologies.[5]

Q. How does Idaho Power calculate its EIM benefits?

A. Idaho Power uses a custom, Idaho Power-specific model within a larger software program (SettleCore)[6] to calculate its EIM benefits. Staff is not aware of other utilities who may use a similar software. The model starts with the CAISO methodology and then makes two adjustments related to hydro (zero-cost hydro and net import/export).[7] The zero-cost hydro adjustment was introduced in Idaho Power's 2019 APCU (UE 350),[8] and the Net Import/Export adjustment was introduced in Idaho Power's 2017 APCU (UE 366).[9,10]

Q. What is the value of the EIM benefits included in Idaho Power's 2024 APCU?

A. The Company proposes to include $48,437,136 at the system level ($2,169,984 Oregon-allocated). This is compared to $74,573,326 as calculated by CAISO at the system level ($3,340,885 Oregon-allocated).[11]

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[5] Staff/202, Idaho Power's response to DR 64 (pdf).
[6] Staff/202, Idaho Power's response to DR 68 (pdf).
"SettleCore is a software system from Power Settlements that was designed for energy companies that participate in physical power markets like the EIM. Idaho Power uses various functionalities within SettleCore related to its participation in the EIM including bidding, scheduling, and reporting. Because the EIM benefits model was included as a part of the larger software system, the Company cannot break out either the upfront or ongoing costs specific to the modeling utilized in the APCU EIM benefits determination."
[7] Staff/202, Idaho Power's response to DR 68 (pdf).
[8] UE 350 Idaho Power/300, Annis/7-11.
[9] UE 366 Idaho Power/100, Blackwell/14-18.
[10] For a complete description of how these were calculated in past APCUs, see the Company's response to DR 28 (pdf) in Staff/202.
[11] Idaho Power/106, 2024 EIM Benefits (excel).

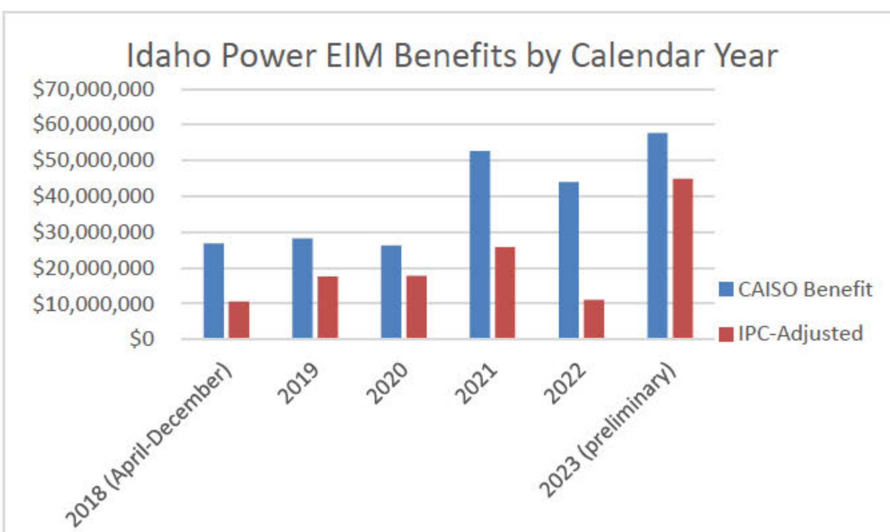
Q. What is Staff's position regarding Idaho Power's substitution of its own calculation of benefits for those estimated by CAISO?

A. At this time, Staff believes Idaho Power's method is acceptable. However, CAISO's method is useful when comparing total EIM benefits and how those benefits have grown for all participants.

Q. How do CAISO benefit calculations compare to the Idaho Power Adjusted figure for each calendar year (Q1-Q1)?

A. The figure below is illustrative of the difference between CAISO benefit estimates and the IPC-adjusted figures. Please note that these values may not reconcile with each APCU's filed benefit amount as these numbers are rerun after APCU filings to capture the most up to date data and to include any updates from Power Settlements. Staff asks that Idaho Power provide a description that elaborates on the timing of updates to EIM benefits.

FIGURE 2: CALENDAR YEAR EIM BENEFITS FOR IDAHO POWER[12]



[12] Staff/202, Idaho Power's response to DR 28 Attachment 1 (excel).

Q. Does Staff propose an adjustment to EIM benefits?

A. Yes, Staff proposes a change to the EIM benefit calculation model, which in turn produces a monetary increase to EIM benefits, which are an offset to total Net Power Supply Expenses (NPSE). Staff proposes to include a growth factor[13] to the final forecast of EIM benefits included in the March forecast and in subsequent APCUs. Staff proposes to update this value with the newest data available in each filing year for future growth factor values. Using the most recently available data, the growth factor for this year's APCU is 61 percent. This results in a $2,740,735 upward adjustment to the Test Year EIM benefits at the system level using the figures reviewed so far from the October update.

Q. Why should the EIM include a growth factor?

A. The EIM should include a growth factor for four main reasons.

1. The APCU is a forward-looking forecast and IPC's current model is backward-looking.
2. EIM benefits have tended to grow every year for all participants in the EIM even if that growth has not been monotonically increasing.
3. In theory, growth in EIM benefits is expected to continue in future years as more members join.
4. While there is volatility in EIM benefits and power costs, utilities should share risk between shareholders and ratepayers.

Q. You state that IPC's models is backward looking. Please explain.

[13] Also known as a percentage change, escalation, or adjustment factor that is applied to the test year forecast by multiplying the two values.

A. The Company uses data from February 2022 to January 2023, with no escalation, to estimate benefits for the 2024 Test Year. If we look back to Fall 2017, we see the Company began including EIM benefits in the October Update Opening Testimony for UE 333 despite the fact that IPC's participation was set to commence on April 1, 2018. IPC stated, "NPSE requested for approval for the 2018 October include both the incremental benefits and costs associated with Idaho Power's planned participation in the Western EIM."[14] At the time there were uncertainty around benefit levels, so EIM benefits were set equal to costs, which resulted in a net zero impact to NPSE for the 2018 APCU. However, by forecasting the costs and benefits, we see the Company was acknowledging the anticipated inclusion and growth of benefits in the upcoming year. In addition, other utilities such as PacifiCorp acknowledge the forward-looking nature of the APCU by considering things such as forward market prices in their EIM benefit calculations.

Q. Please demonstrate how EIM benefits have tended to grow every year.

A. See Table 1 below that shows the annual growth of all EIM participants from Q3 to Q3 beginning in 2015.[15] Only one year showed a negative average growth rate when averaging all participants and it is worth nothing that during the same period, Idaho Power's benefits growth put them in the upper half of participants.[16] For reference, Idaho Power had growth rates of

[14] UE 333 Idaho Power/100, Blackwell/15.
[15] See Staff/203, Staff Workpaper EIM Benefit Calculations.
[16] Averages tend to be pulled towards the outliers so while Idaho Power is below the average during some years, they have tended to have higher growth rates when compared with other utilities, putting them in the upper half with a higher rate for most years.

102 percent, -35 percent, and 109 percent in the most recent three time periods displayed below (Q3 2020-Q3 2023). Apart from Q3 2021-2022, Idaho Power has growth rates higher than the majority of individual participants.

TABLE 1: AVERAGE GROWTH IN CAISO BENEFIT VALUES FOR ALL PARTICIPANTS

Year Ending	Average Growth	Participant Count
Q3 2015 - Q3 2016	114%	2
Q3 2016-Q3 2017	32%	3
Q3 2017-Q3 2018	42%	5
Q3 2018-Q3 2019	22%	6
Q3 2019-Q3 2020	-12%	8
Q3 2020-Q3 2021	75%	9
Q3 2021-Q3 2022	65%	11
Q3 2022-Q3 2023	147%	15

Q. Was the growth in EIM benefits demonstrated in past testimonies as well?

A. Yes. In UE 366, Staff calculated the average growth rate in EIM benefits ranged from 22 to 42 percent depending on how it was calculated.[17] Staff then used the most conservative of the three numbers for their recommended growth factor/adjustment.

Q. Why is EIM benefit growth expected in upcoming years?

A. Benefit growth has varied and can be dependent on many factors including but not limited to: number of participants in the market, hydro conditions, market and gas prices, and transmission constraints, and the overall flexibility of the

[17] The parties to UE 366 agreed Company would provide a 2.3 percent inflationary increase to the Company's March forecast benefit of $16.5M.

resource stack.[18] Therefore, Staff anticipates with the advent of the Extended Day-Ahead Market (EDAM), that EIM participants and bid-in resources may grow as it has since its inception in 2014. It is important to note that at this time many utilities have not bid in much of their resources, which does leave some room to grow in participation in the future. For example, PGE's power operations and IT departments have been working on technology platform improvements to scale the number of resource integrations into the EIM market each year.[19] This distribution of cost-effectiveness benefits to customers from operational efficiencies and enhanced market structures (e.g., EIM, EDAM, RTO, etc.), should not be understated.

Q. Does Idaho Power have plans to join a regional structured market?

A. No, a decision has not been made. "Idaho Power is in the process of evaluating the costs and benefits of market participation. Analysis to support joining—or abstaining from—a market is not completed and, therefore, not available at this time."[20]

Q. Explain Staff's position on how risk should be shared between shareholders and ratepayers.

A. Volatility between forecasted and actual benefits is expected to a certain extent given how volatile power costs can be. The Commission has anticipated this and has protections in place such as the multiple elements of the PCAM. In the

[18] This was included in a document shared by IPC prior to our January workshop, which provided answers to some of our initial questions.
[19] UE 416 PGE/600, Ajello–Batzler/30.
[20] Staff/202, Idaho Power response to DR 48 (pdf).

case of where there is a difference between forecasted and actual power costs for Idaho Power, much of this difference would get absorbed by the deadband as part of the PCAM. This could actually benefit shareholders if EIM benefits are exceptionally high. The positive deadband requires Idaho Power to absorb excess power expense that is the dollar equivalent of 250 basis points of ROE, or excess power cost savings that is the dollar equivalent of 125 basis points of ROE. If there is variance that is above or below the deadband, a sharing mechanism allocates 90 percent to customers and 10 percent to the company. Next, an earnings test provides that if Idaho Power's earned ROE is within plus or minus 100 basis points of its allowed ROE, there is no recovery from or refund to customers. Recovery is allowed beyond the 100-basis point earning test deadband, up to an earnings level that is 100 basis points within the authorized ROE.

Q. How did Staff calculate the growth factor?

A. See Staff Workpaper EIM Calculations, tab Growth Factor Calculation where all cells and formulae are intact. Staff took the percentage of growth for each participant from Q3-Q3 of each period. Then, Staff took all of the percentages and averaged them together to look at the average level of growth of all participants. As a last step, Staff averaged all of the growth rates for all participants in all periods since 2015. As a result, Staff found that on average for all years of the EIM, the average growth rate of benefits per participants was 61 percent.

Q. Why is Staff's method of calculating the growth factor the correct option?

A. Using all years of WEIM history allowed Staff to get a perspective of what the growth rate was since the inception of the WEIM. This is more beneficial than isolating a fewer number of years, since we are able to see a better trend over time and for the growth factor to not be as representative of one year of volatility. In addition, the WEIM is intended to be more efficient as time goes on and more participants are added. Staff chose to look from Q3-Q3 since Q4 data is not yet available and Staff wants the dataset to be as complete as possible and the Test Year is from April 2024 to March 2025. Still, the EIM benefit totals are updated in the March forecast to provide a more accurate look at what benefit totals will be in the upcoming test year. Staff anticipates this growth factor value to be updated with the most recent information in future years.

ISSUE 2. NATURAL GAS COSTS

Q. What sources does Idaho Power use for its gas forwards that are used in the APCU forecast?

A. Idaho power utilizes the price forecast from S&P Global Platts', the EIA's short term energy outlook forecast, Intercontinental Exchange (ICE) forward gas settlements, and Moody's Nymex natural gas futures prices.[21] For purposes of forecasting gas prices at existing units (Langley Gulch, Bennet Mountain, and Danskin), the Company uses the Sumas Hub. However, for gas prices at Bridger Units 1 and 2, they utilize the Opal hub (aka Rockies).[22]

Q. What is the breakdown of the percent of gas purchased at the different hubs?

A. Please see Table 3 below, which provides the percentage of gas purchased by hub. See Staff Exhibit 202 for additional information regarding dekatherms and cost for the different hubs.

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[21] Staff/202, Idaho Power's response to DR 21 (pdf).
[22] Staff/202, Idaho Power's response to DR 22 (pdf).

TABLE 2: PERCENTAGE OF GAS PURCHASED BY IDAHO POWER BY HUB[23]

% of Gas Purchased by Hub			
	Sumas	**Stanfield**	**Wyoming**
2019	37%	52%	11%
2020	34%	50%	16%
2021	42%	55%	3%
2022	50%	50%	0%

Q. What two gas prices are referenced in the Direct Testimony of Idaho Power witness Jessica Brady?

A. The Idaho Citygate and the Bridger prices. The Idaho Citygate price is representative of the gas prices delivered to Langley Gulch, Bennett Mountain, and Danskin. It consists of the Sumas price (Henry Hub price + Sumas basis), and transport/storage costs. Similarly, the Bridger price is representative of the gas price for deliveries to Bridger Units 1 and 2. It consists of the Rockies price (Henry Hub + Rockies basis) and transport/storage costs. The pipeline fees include a volumetric charge of $0.000317 per MMBTu and a fuel rate of 0.48 percent.[24]

Q. What gas expense is included in the test year?

A. Natural gas expense is $163.4 million, compared to $53.3 million in 2023, an increase of 206 percent. This is mostly due to the volume of natural gas generation which has increased to 3.03 million MWh compared to 1.13 in 2023 (an increase of 170 percent). The increase in generation is related to the

[23] *Ibid*.
[24] *Ibid*.

conversion of Bridger Units 1 and 2 to natural gas and the increase in opportunity to make off system economic sales.

Q. What is the price of natural gas per MMBtu?

A. The market price associated with surplus sales is $43.29 per MMBtu, compared to $35.56 (an increase of 22 percent). The Henry Hub price is $3.9 per MMBtu, a 33 percent decrease from last year. The Idaho Citygate price is $5.21, down from $5.63 per MMBtu. Hydro supplies 48 percent, thermal generation is 30 percent and purchases 35 percent of the Company's supply-side resources. Of the 19.33 million MWh generated by the system, 17.26 million MWh are used for system loads while 2.06 million MWh are sold as surplus sales.

Q. Does Staff have any recommendations related to natural gas?

A. At this time, no. This issue is meant to provide a contrast to last year's APCU and explain how natural gas reliance has increased.

ISSUE 3. AURORA MODELING AND RESULTS

Q. What is Aurora?

A. "Aurora models wholesale electricity prices in a competitive energy market, where at any given time, prices are based on the marginal cost of production in each zone. By simulating supply-side resources (both economic and physical characteristics) as well as customer demand in the region, the model determines which resource is on the margin for each zone in any given hour. As a part of this simulation, AURORA determines when it is economic for a zone to purchase power, or when it is economic for a zone to generate additional energy to sell power to another zone. In this APCU, there were hours in the simulation where AURORA determined that it was economic to generate additional energy in order to sell in the market."[25] The same analysis that AURORA does occurs when determining the economics of off-system sales.

Q. Describe off system economic sales.

A. The goal of the AURORA power cost simulation is to minimize system costs while serving demand and obeying operating constraints. In other words, AURORA will dispatch a resource to sell into the market when it is economic, meets operating constraints, and Idaho Power's customer load (demand) is met in each hour.[26]

[25] Staff/202, Idaho Power's response to DR 23.
[26] See Idaho Power/100, Brady/9.

Q. Given that the market price associated with surplus sales increased by 22 percent, to $43.29, explain how this impacts Idaho Power's revenues and expenses.

A. Surplus sales revenue is equal to the total megawatt-hours ("MWh") sold multiplied by the market price. If the market price on a sale is higher, than the total revenue for the sale will be higher. Surplus sales revenue serves as an offset to power supply expenses.[27]

Q. Detail how AURORA is used and when repricing was established.

A. Per Order No. 08-238, the output of the AURORA model will be used to determine net power supply average dispatch cost for normal loads and average stream flow conditions, and the wholesale electric prices for purchased power and surplus sales determined by the AURORA model will be replaced with an average forward electric price curve (which is essentially the repricing that happens).[28]

Q. What was the effect of re-pricing in the 2023 October Update?

Purchased power expenses increased by $66.6 million, moving from $50.7 million to $117.3 million. Please see Lines 33 and 59 of Exhibit 101 show the purchased power expenses and surplus sales revenues, respectively, as determined by the AURORA modeling/repricing process. Surplus sales revenues increased by $57.3 million, moving from $106.6 million to $164.0 million. In this case, the NPSE resulting from the re-pricing

[27] Staff/202, Idaho Power's response to DR 24 (pdf).
[28] In UE 384, Order No. 21-165 made two additional changes to repricing.

methodology shown in Exhibit 105 is an increase in NPSE of $9.3 million as compared to the AURORA-generated expense shown on Exhibit 101.[29]

Q. Has the Company provided copies of the AURORA files?

A. Yes, these were provided in response to Staff DR 43.

Q. Does Idaho Power perform a backcast?

A. No, Idaho Power does not perform a model backcast for AURORA. In simulating the economic dispatch of Idaho Power's system, AURORA develops market prices based on regional conditions in the WECC. Because the model is not designed to receive market prices as an input, the Company could not input historical market prices and perform an accurate backcast. However, Idaho Power does perform several post-modeling checks to ensure that AURORA is functioning properly and that the output is reasonable given the inputs. Three of the most recent analyses have been provided in a Confidential response to DR 46. Staff has not found any issues at this time and has no related recommendations.

Q. Please discuss the new resources included in the calculation of NPSE.

A. The Company proposes to include the Bridger conversions and three PPAs to the calculation of NPSE since last year's 2023 October update.

1) Bridger Units 1 and 2 will be converted to natural gas by Summer 2024 and were modeled as natural gas resources for the 2024 APCU test year.[30] The conversion of the Bridger units from coal to natural gas

[29] AURORA Repricing was discussed in more detail in UE 414 Staff/100.
[30] Idaho Powe/100, Brady/12.

reduces the forecast for coal-fired generation by 15 percent compared to last year. However, the conversion of the Bridger units is also cited as a primary driver for a 170 percent increase in natural gas generation.

2) Franklin Solar is a 100-MW facility scheduled to come online June of 2024.[31] It is a 25-year Power Purchase Agreement (PPA) with Franklin Solar, LLC. Franklin BESS, co-located with Franklin Solar, is a Build Transfer Agreement with Duke Energy Renewables Solar LLC, providing for a minimum capacity of 60 MW.

3) The Hemingway BESS resource represents the addition of 36 MW of Idaho Power-owned battery storage at the Hemingway substation.[32] Both the Franklin BESS and the Hemingway BESS resources were modeled so that the scheduled generation of each battery is shaped to the Company's demand, net of the "must-run" PURPA and PPA resources.

4) Pleasant Valley Solar is a 200-MW facility scheduled to come online March of 2025.[33] The solar facility is a PPA with Bisbee, LLC. Meta Platforms Inc. is the parent company of Brisbie. Pleasant Valley Solar will be connected to the Company's system and will not serve Brisbie directly. However, Brisbie will pay for the full cost of the PPA, as well as the service required to support their load by Idaho Power. In addition, Brisbie will receive the value that the Pleasant Valley resource provides Idaho Power's system and will be credited for any PPA generation that exceeds

[31] Ibid.
[32] Ibid.
[33] Idaho Power/100, Brady/13.

their load in a given hour. Because the Pleasant Valley resource comes online prior to Brisbie's load in December 2025, the expenses associated with Pleasant Valley Solar in this APCU test year represent the excess generation from the PPA, as well as the capacity contribution.

Q. How did the Company handle the new resources for the 2024 Test Year?

A. Staff's understanding is that the "new resources" above were modeled as annualized online resources for the entire Test Year.[34] All of the new resources were added to the AURORA model for this year's October Update in order to calculate a "base" or "normal" level of NPSE.[35]

Q. Does Staff have any objection to the Company's handling of new resources?

A. No, not at this time. The Company followed the same treatment applied to new projects in prior APCU dockets when they were scheduled to come online during an APCU Test Year. However, Staff does ask that Idaho Power make a distinction in filings between those resources that are PPAs vs. those that are considered new resources and are therefore a part of rate base.

Q. Does this conclude your testimony?

A. Yes.

[34] Although New Resources and PPAs were used interchangeably in discussions and prior testimonies. Staff's understanding with the resources above are that they are power purchase agreements and are not rate based. Therefore, they are included in the model starting with the month they are coming online.
[35] Exhibit 100, Brady/12.

CASE: UE 425
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

January 31, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME: Julie Dyck

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Rates, Finance and Audit Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: I have a Bachelor of Science from Berea College in Political Science. I also hold a Masters of Integral Economic Development Policy specializing in the public sector and econometrics. I have completed rate school with NARUC, a data analytics course with Google, and am currently a NABE Frank Schott Scholar working towards becoming a Certified Business Economist.

EXPERIENCE: I have been employed as a Junior Financial Analyst by the Oregon Public Utility Commission since June 2021 in the Telecommunications and Water division. I transitioned to the ERFA Division in July of 2022. Within this division, I currently perform a range of financial analysis duties related to natural gas and electric utilities, with a focus on Power Cost filings. In addition, I assist with Purchased Gas Adjustments, Annual Power Cost filings, and General Rate Cases. Rate case experience include: UG 435, UE 399, UE 416, and UG 461. I was previously employed as an adjunct professor of Econometrics at the Catholic University of America and as an Analyst in the Office of Management and Budget (OMB) within the Executive Office of the President (EOP), where I worked as part of a team on higher education funding. Prior to EOP, I was an Economic Consultant for the U.S. Conference of Catholic Bishops.

CASE: UE 425
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

January 31, 2024

UE 425
Idaho Power Company's Response to Staff's Data Request Nos. 1-20
Topic or Keyword: EIM

STAFF'S DATA REQUEST NO. 19:

Please explain how the Company determines whether to transact in the day-ahead/month ahead market rather than EIM. Please also explain how the Company optimizes its operations to maximize benefits in the EIM.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 19:

On a day-ahead basis, and subsequently in real-time, Idaho Power plans its resources and makes purchases, as necessary or economic, to meet the forecasted load for the trade day in question. While the day-ahead plan is set up one or more days in advance, by the time the operating day begins, circumstances may have changed that necessitate additional real-time bilateral wholesale market activity, even absent the EIM. Variable energy resources may be producing generation higher or lower than forecast, actual load may be coming in higher or lower than forecast, resources may be unexpectedly unavailable or return to service earlier than expected, etc. Idaho Power may need to purchase energy bilaterally or take other action to balance its resources and load given these changing conditions.
Thus, the EIM is not the only real-time option for transactions. Further, and critically, the EIM is not a capacity market, but rather an intra-hour energy imbalance market. Participants in the EIM must enter each operating hour with a balanced load and resource portfolio, which may include energy purchases or sales that were transacted in the real-time, day-ahead, or month-ahead bilateral market. The EIM resolves imbalances in load and resources that occur within the operating hour and will optimize economic dispatch of participating resources that submit bids into the market. Thus, an EIM participant must come into each hour balanced with resources sufficient to meet its forecasted load and cannot lean on the market for capacity and energy. As a result, Idaho Power cannot defer purchases it would otherwise need to make for load service to the EIM. Participants who come into an hour outside the EIM's thresholds may face penalties or consequences, including restrictions from participation in the EIM.

Idaho Power operates with the goal of reliably serving its customers in the most economical, least-cost manner. This is true regardless of the timeframe in which transactions occur: real time bi-lateral, day-ahead, balance of month, term, or EIM. Idaho Power sets up its resources in each timeframe to most economically serve load given its own resource stack. In the EIM, Idaho Power's participating resources may subsequently be dispatched down (if the EIM determines resources in another area can more economically serve load) or up (if the EIM determines Idaho Power's participating resources are the most economical next resource to run to serve load).

UE 425
Idaho Power Company's Response to Staff's Data Request Nos. 64-69
Topic or Keyword: EIM

STAFF'S DATA REQUEST NO. 64:

See Idaho Power/100, Brady/25-30. Is Idaho Power aware of any other EIM participants who adjust the CAISOs EIM benefits obtained from the CAISOs EIM Benefit Methodology for ratemaking or other purposes?

a. If so, detail who those participants are and what type of adjustments they are making.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 64:

Idaho Power is generally aware that other utilities are performing their own forecast or calculation of Energy Imbalance Market ("EIM") benefits, but does not know the details behind the calculations or methodologies.

Idaho Power Company's Response to Staff's Data Request Nos. 64-69

Topic or Keyword: EIM

STAFF'S DATA REQUEST NO. 68:

Explain the decision to make adjustments to CAISO's methodology and the process in developing the model Idaho Power currently used for EIM benefits calculations.

a. Where did Idaho Power get the model from? Is Idaho Power aware of this model being used by other participants?
b. How much did the model cost and are there ongoing costs associated with using the model?

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 68:

Idaho Power's current Energy Imbalance Market ("EIM") benefits model consists of starting with the CAISO methodology, and then making two adjustments related to hydro (zero-cost hydro and net import/export). The decision to make these adjustments is detailed in each Annual Power Cost Update ("APCU") filing. However, the Company has provided below the pages of testimony that reference the first time these adjustments were introduced.

- Zero-cost hydro adjustment: UE 350, Idaho Power/300, Annis/7 – 11. - Net import/export adjustment: UE 366, Idaho Power/100, Blackwell/14 - 18.

a. Idaho Power uses a custom, Idaho Power-specific model within a larger software program (SettleCore) to calculate its EIM benefits. As this model is specific to Idaho Power, the Company is not aware of other utilities that use the same model.
b. SettleCore is a software system from Power Settlements that was designed for energy companies that participate in physical power markets like the EIM. Idaho Power uses various functionalities within SettleCore related to its participation in the EIM including bidding, scheduling, and reporting. Because the EIM benefits model was included as a part of the larger software system, the Company cannot break out either the upfront or ongoing costs specific to the modeling utilized in the APCU EIM benefits determination.

Topic or Keyword: EIM

STAFF'S DATA REQUEST NO. 28:

Please explain the changes in EIM gross and net revenue from the last five APCUs and include any agreed upon settlements that include EIM adjustments or modeling changes.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 28:

Per email communication with OPUC Staff, Idaho Power understands this request to ask for changes in EIM benefits with and without adjustments to the CAISO benefit methodology, including any agreed upon settlements that include EIM adjustments or modeling changes.

Please see Attachment 1 provided with this response for EIM benefits (with and without adjustments to the CAISO methodology) from the 2019 – 2023 APCU filings. A description of the methodology used in each year, including any adjustments related to settlement negotiations, is included below.

2019 APCU

- The level of EIM benefits included in the 2019 APCU was based initially on the
CAISO report of EIM benefits. However, as discussed in both the 2019 March Forecast testimony and the supplemental testimony of Mark A. Annis, the Company identified several issues with CAISO's method of calculating EIM benefits and had been working with Power Settlements and CAISO to shadow and validate CAISO's benefit calculation. After review of the CAISO methodology, the Company determined that additional adjustments were necessary to develop an appropriate EIM benefit amount that reasonably reflected the ongoing cost savings associated with Idaho Power's participation. These adjustments included:
    1) Correction to CAISO's counterfactual methodology – CAISO agreed to correct its counterfactual modeling assumptions for all EIM entities on a go-forward basis. This correction was based on an invalid assumption utilized by CAISO associated with the transfer price as the floor.
    2) Zero-price hydro adjustment – Because hydro is a zero-variable cost resource, Idaho Power bids hydro resources based on an operational value rather than the actual dispatch cost. CAISO's counterfactual dispatch cost is based on bid prices submitted, and as a result, its benefit calculation does not accurately account for this operating scenario.
    3) GHG benefits adjustment - On November 1, 2018, CAISO implemented changes that were approved by FERC to revise its EIM bid adder rules by adding language to its tariff that

limits the hourly dispatchable bid range between the resource's base schedule and its effective upper economic bid for the relevant operating hour. As a result, Idaho Power expected a reduced financial benefit from net GHG revenues relating to selling energy to CAISO and adjusted its EIM benefit amount to reflect the change.

4) Third-party load adjustment – the Company removed the estimated benefits attributed to third-party load in its balancing authority area. <u>2020 APCU</u>

- The level of benefits included in the 2020 APCU was based initially on the CAISO report of EIM benefits and then accounted for necessary adjustments to quantify ongoing cost savings benefits specific to Idaho Power's participation in the EIM. These adjustments included:
  1) Zero-price hydro adjustment (no change in methodology from prior year)
  2) Hydro net export/import adjustment - Idaho Power adjusted the zeroprice hydro calculated results in #1 by assigning a value to the hydro net imports/exports for each hour based on the Powerdex Mid-C hourly market electricity price.
  3) Third-party load adjustment (no change in methodology from prior year)

- There was also a settlement adjustment resulting in an increase in total EIM benefits of $0.4 million. The Stipulating Parties did not agree that the methodology used to determine the agreed-upon increase was reasonable.

- Changes in Idaho Power methodology from 2019:
- No adjustment to GHG benefits
- Introduction of hydro net export/import adjustment

<u>2021 APCU</u>

- The level of benefits included in the 2021 APCU was based initially on the CAISO report of EIM benefits and then accounted for necessary adjustments to quantify ongoing cost savings benefits specific to Idaho Power's participation in the EIM. These adjustments included:
  1) Zero-price hydro adjustment (no change in methodology from prior year)
  2) Hydro net export/import adjustment (no change in methodology from prior year)

- Changes in Idaho Power methodology from 2020:

1) Third-party load adjustment was removed as recommended by CUB.

2022 APCU

- The level of benefits included in the 2022 APCU was based initially on the CAISO report of EIM benefits and then accounted for necessary adjustments to quantify ongoing cost savings benefits specific to Idaho Power's participation in the EIM. These adjustments included:
  1) Zero-price hydro adjustment (no change in methodology from prior year)
  2) Hydro net export/import adjustment (no change in methodology from prior year)

- No changes in Idaho Power methodology from 2021

2023 APCU

- The level of benefits included in the 2023 APCU was based initially on the CAISO report of EIM benefits and then accounted for necessary adjustments to quantify ongoing cost savings benefits specific to Idaho Power's participation in the EIM. These adjustments included:
  1) Zero-price hydro adjustment (no change in methodology from prior year)
  2) Hydro net export/import adjustment (no change in methodology from prior year)

- There was also a settlement adjustment resulting in an increase in Oregonallocated EIM benefits of $1.0 million. With the inclusion of this adjustment, the
Stipulating Parties agreed that the Company's forecasted EIM benefits for the 2023 APCU were reasonable. However, the Stipulating Parties did not necessarily agree on the methodology used to calculate the adjustment.

- No changes in Idaho Power methodology from 2022.

Idaho Powers non-confidential response to DR 28 is available in electronic spreadsheet format only

UE 425
Idaho Power Company's Response to Staff's Data Request Nos. 21-50
Topic or Keyword: Structured Markets Participation

STAFF'S DATA REQUEST NO. 48:

Detail whether Idaho Power has plans to join a regional market and what the proposed timeline would be.

a. Include any internal presentations, analysis, or written documents that discuss the options that Idaho Power is considering, and options weighed.
b. If the utility has considered regional market participation, please describe the anticipated impacts, changes, or other considerations necessary to appropriately recover or refund power costs in Oregon.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 48:

Idaho Power is in the process of evaluating the costs and benefits of market participation. Analysis to support joining—or abstaining from—a market is not completed and, therefore, not available at this time.

UE 425
Idaho Power Company's Response to Staff's Data Request Nos. 21-50
Topic or Keyword: Natural Gas

STAFF'S DATA REQUEST NO. 21:

Please state where Idaho Power gets their gas price forwards from.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 21:

Idaho Power utilizes S&P Global Platts' price forecast, the Energy Information Agency ("EIA") short term energy outlook forecast, Intercontinental Exchange ("ICE") forward gas settlements, and Moody's Nymex natural gas futures prices.

UE 425
Idaho Power Company's Response to Staff's Data Request Nos. 21-50
Topic or Keyword: Natural Gas

STAFF'S DATA REQUEST NO. 22:

How many different natural gas market forecasts does Idaho Power consider in addition to the Henry Hub and the Idaho Citygate price mentioned?

a. Provide breakdowns of the trading percentages, in terms of both therms and dollars, that occur at different hubs for each of the calendar years 2019 through 2022.
b. Detail in an Excel workbook which units are using which prices for natural gas.
c. See Idaho Power/100 Brady/10, how was the average natural Bridger gas price of $4.43 determined?

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 22:

For purposes of forecasting gas prices at its existing natural gas units (Langley Gulch, Bennett Mountain, and Danskin), Idaho Power utilizes forward gas prices at the Sumas Hub, located near the Washington-Canada border.

For purposes of forecasting gas prices at Bridger Units 1 and 2, Idaho Power utilizes forward gas prices at the Opal (also referred to as Rockies) Hub, located near the Wyoming-Idaho border.

As discussed in the Direct Testimony of Jessica G. Brady (pages 9-10), the Idaho Citygate prices is representative of the gas prices delivered to Langley Gulch, Bennett Mountain, and Danskin. It consists of the Sumas price (Henry Hub price + Sumas basis), and transport/storage costs. The Bridger price is representative of the gas price delivered to Bridger Units 1 and 2. It consists of the Rockies price (Henry Hub + Rockies basis) and transport/storage costs.

A. Please see the tables below for a breakdown of trading percentages in both Dekatherms ("Dth") and dollars for 2019 – 2022.

Dth of Gas Purchases by Hub			
	Sumas	**Stanfield**	**Wyoming**
2019	4,875,849	6,855,300	1,513,434
2020	5,476,700	7,873,232	2,548,482
2021	7,880,809	10,282,536	503,937
2022	7,702,936	7,787,130	49,410

Cost ($) of Gas Purchases by Hub			
	Sumas	**Stanfield**	**Wyoming**
2019	$19,011,577	$22,594,201	$2,906,421
2020	$12,204,360	$18,465,419	$4,959,534
2021	$29,501,963	$39,375,691	$2,614,878
2022	$63,074,901	$88,504,553	$122,675

% of Gas Purchased by Hub			
	Sumas	**Stanfield**	**Wyoming**
2019	37%	52%	11%
2020	34%	50%	16%
2021	42%	55%	3%
2022	50%	50%	0%

B. Please refer to Confidential Workpaper 7 – Gas Financial Forecast, provided on November 7, 2023. The tab labeled "Gas" shows the calculation for the Idaho Citygate price (L28). This price is applied to Langley Gulch, Danskin, and Bennett Mountain. The tab labeled "Bridger Gas" shows the calculation for the Bridger price (L28). This price is applied to Bridger Units 1 and 2.

C. The Bridger Gas price of $4.43 is comprised of the annual average Henry Hub price + annual average Rockies basis + Mountain West Overthrust pipeline fees. The pipeline fees include a volumetric charge of $0.000317 per MMBTu and a fuel rate of 0.48 percent.

UE 425
Idaho Power Company's Response to Staff's Data Request Nos. 21-50
Topic or Keyword: Natural Gas

STAFF'S DATA REQUEST NO. 23:

See Idaho Power/100 Brady/9, which says, "The 170 percent increase in natural gas generation can be attributed to the increase in capacity related to the conversion of Bridger units 1 and 2 to natural gas, as well as the increase in opportunity to make off-system economic sales".

a. Define off-system economic sales.
b. Explain in narrative format how the increased generation increases the opportunity to make off-system economic sales.
c. In addition, describe to what extent the generation from natural gas is used for off system economic sales compared to those that are used to serve load.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 23:

a. Off-system economic sales, in the context of the AURORA model, are sales of energy from Idaho Power's zone to another zone in the Western Electricity Coordinating Council ("WECC").[1]

b. AURORA models wholesale electricity prices in a competitive energy market, where at any given time, prices are based on the marginal cost of production in each zone. The simulation of supply-side resources (both economic and physical characteristics) as well as customer demand in the region allows the model to determine which resources are on the margin for each zone in any given hour. As a part of this simulation, AURORA determines when it is economic for a zone to purchase power, or when it is economic for a zone to generate additional energy to sell power to another zone. In this case, there were hours in the simulation where AURORA determined that it was economic to generate additional energy in order to sell in the market.

c. The output data available in AURORA does not provide the level of detail needed to determine how much generation from a given resource was used for sales versus how much was used to serve load. However, the goal of the AURORA power cost simulation is to minimize system costs while serving demand and obeying operating constraints. In other words, AURORA will only dispatch a resource to sell into the market when it is economic, meets operating constraints, and Idaho Power's customer load (demand) is met in each hour.

[1] A zone in the AURORA model is similar to a balancing authority ("BA").

UE 425
Idaho Power Company's Response to Staff's Data Request Nos. 21-50
Topic or Keyword: Natural Gas

STAFF'S DATA REQUEST NO. 24:

See Idaho Power/100 Brady/9. Given that the market price associated with surplus sales increased by 22 percent, to $43.29, explain how this impacts Idaho Power's revenues and expenses. Is Staff's understanding correct in that the market price is higher and therefore, the Company is receiving a higher MWh rate for surplus sales.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 24:

Yes. Surplus sales revenue is equal to the total megawatt-hours ("MWh") sold multiplied by the market price. If the market price on a sale is higher, than the total revenue for the sale will be higher. Surplus sales revenue serves as an offset to power supply expenses.

CASE: UE 425
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Opening Testimony

January 31, 2024

Staff Workpaper titled EIM Benefit Calculations is available in electronic spreadsheet format only

CASE: UE 425
WITNESS: Dean Ratliff

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

January 31, 2024

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

A. My name is Dean Ratliff. I am a Senior Utility Economist employed in the Energy Cost Section of the Rates, Safety and Utility Performance (RSUP) Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. I address Public Utility Regulatory Policies Act (PURPA) expenses and the Demand Response Program proposed by Idaho Power Company's (Idaho Power, IPC, or Company) in their 2024 Annual Power Cost Update filing (APCU).

Q. Did you prepare exhibits for this docket?

A. Yes. I prepared Exhibit Staff/301 and Exhibit Staff/302, which is an Idaho Power Confidential Response to a Staff Data Request.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. PURPA: QF EXPENSE

Q. What is the Public Utility Regulatory Policies Act (PURPA)?

A. Per the OPUC website:

> In 1978, Congress passed the PURPA to encourage fuel diversity via alternative energy sources and to introduce generation supply competition into the electric sector. The legislation originally encouraged industrial waste heat recovery and renewable energy resource development by small, non-utility power producers called "Qualifying Facilities" or "QFs." Now, wind, solar and other types of developers use PURPA to sell power at "avoided cost" rates to Oregon's utilities. Although PURPA is a federal law, states are responsible for implementing significant aspects of the law, and Oregon has enacted its own complementary legislation in ORS 758.505-.555.[1]

Q. What changes have there been in expected forecasted generation and cost since last year's October Update for PURPA?

A. In the October Update of the previous year, Idaho Power forecasted 362.0 average megawatts (aMW) of PURPA generation. In the 2024 October Update, Idaho Power forecasted PURPA generation of 354.7 aMW, reflecting a decrease of 7.35 aMW, equivalent to a 2.03 percent reduction. This decline in PURPA generation can be attributed primarily to the regular fluctuations in estimated output from the Company's existing PURPA-contracted facilities.[2] In this year's October Update, the forecasted PURPA expense is $250.3 million, marking an increase of $3.0 million, or one percent, in comparison to the forecast from the previous year. When compared to the settled PURPA expense amount from the previous year, this year's forecast represents an increase of

[1] *Online Research (Public Utility Commission: PURPA: Utility Regulation: State of Oregon).*
[2] See the Company's Opening Testimony Exhibit 100, Brady/11.

$10.1 million, or four percent. The rise in the forecasted annual PURPA expense is mainly attributed to updated PURPA contract values. However, this increase is partially offset by a decrease in the forecasted generation.[3]

Q. How accurate have PURPA expenses estimates been in the past?

A. The expense forecast for purchases from Qualifying Facilities (QFs) has been consistently overestimated in recent years. Conf Table 1 below shows the difference from the forecasted and actual PURPA expenses.

CONF TABLE 1: PURPA EXPENSE[4]

[BEGIN CONFIDENTIAL]

	Projected[5]	Actual	Difference	Projected to Actual
2019 Test Year	[redacted]	[redacted]	[redacted]	[redacted]
2020 Test Year	[redacted]	[redacted]	[redacted]	[redacted]
2021 Test Year	[redacted]	[redacted]	[redacted]	[redacted]
2022 Test Year	[redacted]	[redacted]	[redacted]	[redacted]
2023 Test Year	[redacted]	[redacted]	[redacted]	[redacted]
3 Year Average	[redacted]	[redacted]	[redacted]	[redacted]

[END CONFIDENTIAL]

Table 1 illustrates that the Company's forecasts have resulted in overestimation of PURPA expenses. In fact, over the last four years the Company has over collected **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Over the last three years, the actual

[3] See the Company's Opening Testimony Exhibit 100, Brady/11.
[4] Staff/302, IPC CONF response to Data Request No. 56 Attachment 1.
[5] Based on Oregon repricing.

PURPA expenses on average have been **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Has Idaho Power provided an explanation for the overcollection?

A. Yes. Idaho Power's explanation can be seen in last year's APCU filing. Idaho Power explained that since 1983, Idaho Power has forecasted costs for PURPA contracts in Oregon based on the assumption the rates paid to QFs are non-levelized.[6] Accordingly, when determining the revenue requirement for any non-levelized contracts, it is assumed the PURPA generation of levelized contracts is being purchased at the rate it would have been without levelization. As Idaho Power pointed out in last year's APCU, the Oregon re-pricing methodology would result in collection of less than actual costs in early years of contracts and collection of more than actual costs in the later years of those same contracts.

Q. Are you satisfied with this explanation of the over forecast?

A. No. Staff remains concerned because Idaho Power has not substantiated the alleged reason for the over forecast with evidence showing the earlier under recovery of PURPA costs. We do not dispute the potential for Oregon's re-pricing methodology to result in what appear to be over forecasted costs in the later years of a contract. However, there is no evidence to show that the Oregon method results in the under recovery of PURPA costs that requires the magnitude of over forecasting seen in Idaho Power's APCU.

Idaho Power has over forecasted PURPA expense in its APCU in every year but one since 2015. However, since 2015, the term of Idaho PURPA

[6] UE 414 Idaho Power/200, Brady/2-3.

contracts for QFs larger than 100 kW has been two years. Staff does not expect an under/over forecasting issue with two-year contracts.[7] And, to the extent there were levelized contracts in Oregon prior to the date in 2005 when the Commission adopted the non-levelization policy, the fixed-price term of those non-levelized contracts ended no later than 2020.[8]

Q. What do you recommend for PURPA expenses?

A. Staff recommends the continued use of the Oregon repricing method for forecasting PURPA expenses reduced by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to align the forecasted with the historical actual expenses. This results in a PURPA expense amount of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the $250.3 million proposed by the Company, based on the three-year average of actual to projected.

[7] IPUC Order Nos. 33-357 and 33-419.
[8] See OPUC Order No. 05-525 (Contracts executed between 1997 and 2005 have five- year terms and contracts executed after 2005 have a fifteen-year fixed cost period).

ISSUE 2. DEMAND RESPONSE

Q. What is the Company's position on Demand response?

A. The Company has incorporated forecast demand response in the 2024 APCU model, modeling it based on the parameters of three programs: A/C Cool Credit, Flex Peak Program, and Irrigation Peak Rewards. Drawing from actual 2022 participation data, the Company anticipates that these programs will contribute a total of 320 MW of peak capacity from June 1 to September 15. It's important to note that no expenses related to demand response have been included in this filing.[9]

Q. Do you have any objections to the Company's position?

A. No, not at this time.

Q. Does this conclude your testimony?

A. Yes.

[9] Idaho Power/100, Brady/19.

CASE: UE 425
WITNESS: DEAN RATLIFF

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

January 31, 2024

WITNESS QUALIFICATION STATEMENT

NAME:	Dean Ratliff
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Economist Rates, Safety and Utility Performance Program
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Master of Business Administration, Regulatory Economics New Mexico State University, Las Cruces, NM Bachelor's Business Administration, Finance New Mexico State University Las Cruces, NM
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission (OPUC) since November 2023 in the Energy Costs Section Manager. My responsibilities include analyzing, advising, and providing testimony on various issues in front of the Oregon Public Utility Commission. Prior to working for the Commission, I was a business leader and regulatory expert with nearly 25 years of regulatory experience. I had a 10-year career with Southern California Edison and nearly 15 years of experience as a regulatory consultant.

CASE: UE 425
WITNESS: DEAN RATLIFF

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

January 31, 2024

Topic or Keyword: PURPA

STAFF'S DATA REQUEST NO. 56:

Please provide an updated response with the most current values.

Please provide the following information in Excel format:

a. Projected QF supplied power for each QF, as reflected in rates for each test year from 2019 through 2023. Please include MWh, MW and the projected purchased power cost in dollars.
b. Actual QF supplied power for each QF, for each test year from 2019 through 2023. Please include MWh, MW and the actual purchased power cost in dollars.
c. The ratio of actual to projected QF purchased power costs for each test year from 2019 through 2023.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 56:

Please see the confidential attachment provided with this response.

CONF Attachment 1 to IPC Response to Staff DR 56 is filed in electronic format only.

CASE: UE 425
WITNESS: Rose Pileggi

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

January 31, 2024

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

A. My name is Rose Pileggi. I am a Senior Utility Analyst employed in the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/401.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a summary of Staff analysis of coal costs and coal related costs in Idaho Power Company's (Idaho Power, Company, or IPC) 2024 Annual Power Cost Update (APCU) filing.

Q. Did you prepare any exhibits for this docket?

A. No. No exhibits were prepared beyond the witness qualification statement.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. COAL FUEL EXPENSE

Q. Please detail the changes to coal fuel expenses in Idaho Power's 2024 APCU.

A. Idaho Power's October 2024 APCU coal fuel expenses totaled $84.6 million. This represents an increase of $2.5 million, approximately a 3 percent change, over the October 2023 APCU total of $82.1 million. Coal generation totaled 2.08 million MWh, a decrease of 0.38 million MWh—or approximately 15.4 percent—from the 2.46 million MWh in the October 2023 update.[1]

Q. Please explain why the total coal fuel expenses have increased since the last APCU filing despite a 15.4 percent decrease to generation.

A. The primary drivers to the increased costs include an increase to Bridger fuel costs of roughly 10.7 percent, from $32.15 per MWh in the October 2023 to $35.59 per MWh in the current filing,[2] and a shift in the generation mix between the cheaper Bridger units, to the relatively more expensive Valmy plant.[3] The change in the generation mix between the two coal plants is occurring as Bridger 1 and 2 are being converted from coal to natural gas. These increases were partially offset by a 31 percent decrease to Valmy coal fuel costs. The increase to fuel costs is due to the switch to higher cost natural gas after the conversion is complete.

[1] See Idaho Power/100, Brady/6
[2] *Ibid.*
[3] In the 2023 APCU, Valmy generated about 90 MWh of the total 2.46 million MWh—a negligible percentage of the total generation. In the current filing, Valmy is producing 0.468 million MWh, approximately 22.5 percent of total generation.

Q. Did Staff identify any issues with Idaho Power's October 2024 coal fuel expenses?

A. No. Staff issued data requests and spoke with IPC to resolve some questions regarding Idaho Power's coal forecast workpaper. After reviewing the DRs and speaking with IPC, Staff has not yet identified any needed adjustments to IPC's coal fuel expenses as filed in the 2024 APCU.

Q. Did Staff identify any discrepancies in the Oil Handling, Administration, and Generation Expenses (OHAG) in the 2024 APCU?

A. No. Staff found that the calculations used by IPC are in line with the methodology agreed upon in the 2016 and 2017 APCU settlements.

ISSUE 2. BRIDGER 1 AND 2 CONVERSIONS

Q. Please briefly describe the impacts of the Bridger 1 and 2 conversions on the 2024 APCU.

A. Bridger units 1 and 2 are undergoing conversion from coal to natural gas and are modeled as part of the natural gas generation fleet in this filing. The conversion of these two units shifts the cost of generation at Bridger 1 and 2 upwards; reflecting the conversion from the relatively cheaper coal fuel to the relatively more expensive natural gas. No adjustments to filed power costs were identified in relation to the conversion process itself and the units are expected to be available during the test year.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 425
WITNESS: ROSE PILEGGI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

January 31, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME: Rose T. Pileggi

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Energy Costs Section

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: In 2013, I received a Bachelor of Science in Business Administration from Thomas Edison State University. In 2017, I received a Master of Science in Finance from the University of Portland.

EXPERIENCE: I have been employed by the Commission since July of 2022 analyzing finance, power cost, rate case and affiliated interest dockets.

From July 2021 through June 2022, I worked as an Analyst for the Oregon Judicial Department. Duties included data analysis, ensuring compliance with pertinent statutes and rules to ensure that data was being handled in accordance with requirements and recommending process improvements.

From 2017 to 2021, I worked as an Investment Analyst, Portfolio Manager, and Systems Manager for Northwest Capital Management. My work included analysis of the markets and investments, the management and rebalancing of portfolios, creating reports as required by the SEC, as well as managing software integrations for operational and reporting purposes.

CASE: UE 425
WITNESSES: David Abraham & Bret Stevens

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 500

Opening Testimony

January 31, 2024

Q. Please state your names, occupations, and business address.

A. My name is David Abraham. I am a Senior Economist employed in the Energy Costs Section of the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My name is Bret Stevens. I am a Senior Economist employed in the Rates and Telecommunications Section of the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). Our business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational backgrounds and work experiences.

A. These can be found in our witness qualification statements in Exhibit Staff/501.

Q. What is the purpose of your testimony?

A. This testimony provides a summary and analysis of Idaho Power Company's (Idaho Power, Company, or IPC) Net Power Supply Expense calculation (NPSE), revenue requirement, system load, rate spread model, and jurisdictional allocation of net power costs.

Q. Did you prepare any additional exhibits for this docket?

A. No.

Q. How is the testimony organized?

A. The testimony is organized as follows:

ISSUE 1. CALCULATION OF NPSE

Q. What is the purpose of the NPSE and how is it calculated?

A. NPSE is a component of the Company's Annual Power Cost Update (APCU) that is required to be filed in October of every year.[1] The APCU is a rate mechanism that allows the Company to recover allowable costs by aligning power supply expenses included in customer rates with the power supply expenses actually incurred by the Company. The APCU attempts to align these expenses by estimating allowable power costs in a future test year, which are composed of expenses related to fuel costs, purchased power costs, minus surplus sales.

Q. Please discuss any modifications Idaho Power made to the total NPSE calculation in this year's October Update.

A. The Company proposes to include three modifications to the total NPSE calculation in this year's update. The first modification relates to the Black Mesa Solar PPA and a new special contract with Micron Technology, Inc. ("Micron").[2] The special contract states that although the output from the Black Mesa Solar PPA will not serve Micron directly, Micron will pay for all the output. Due to Micron's agreement to pay for 100 percent of the Black Mesa Solar PPA, the cost of the PPA is excluded from the Company's calculation of NPSE. Staff has confirmed that the related sales, expenses, and MWh have been excluded from the final NPSE calculation. The second modification relates to

[1] Order No. 08-238.
[2] Idaho Power/100, Brady/20.

Order No. 35-929, from the Idaho Public Utilities Commission, approving a new special contract with Lamb Weston.[3] The special contract provides for a two-block pricing structure whereby revenues from Block 2 energy sales will be treated as a surplus sale in NPSE calculations. Staff has confirmed that revenues associated with Lamb Weston's forecast Block 2 energy sales have been included as an offset to NPSE and the associated MWh have been removed from the per-unit cost allocation. The third modification is related to third-party transmission wheeling line losses.[4] Third-party line losses represent the additional energy that Idaho Power generates to offset the energy lost from third parties wheeling their power through the Company's transmission system.

Q. Please explain more of the third-party transmission wheeling line losses.

A. This additional load requirement was not previously incorporated into the calculation of NPSE. The Company explains that this issue was discovered as part of the Company's most recent line loss study. The Company states that prior to the Energy Imbalance Market (EIM), wheeling customers had the option to settle their losses by generating the additional physical energy from line losses themselves. However, the Company claims that nearly all wheeling customers now participating in the EIM settle their losses financially. This means that Idaho Power incurs the cost to generate this additional energy and receives compensation from third-party wheeling customers commensurate with this cost. As a result, the Company is proposing to incorporate the cost of

[3] Idaho Power/100, Brady/20.
[4] Idaho Power/100, Brady/21.

the additional generation into the total NPSE. Staff has confirmed that the forecasted revenue expected from third party wheeling customers has been included as an offset to total NPSE. Staff acknowledges that the costs incurred by the Company for line loss generation will not match perfectly to the compensation received for the test year. Idaho Power does not receive the cost of generation for this generation, but instead the price at the Load Aggregation Point (LAP). The LAP price is meant to approximate the cost of generation but may be lower or higher than the true cost of generation. Any deviations between the cost of generation and the LAP price will be trued-up at the Company's subsequent Power Cost Adjustment Mechanism (PCAM) filing.

Q. Is Staff proposing changes to the Company's calculation of NPSE?

A. Staff does not propose any changes to the Company's calculation of total NPSE at this time. However, Staff did discuss the potential for shaping third-party line-loss generation to better reflect the actual timing of when this generation occurs. The timing of line loss generation is important due to the fact that energy prices fluctuate hourly, and matching the generation from line losses to the prices in effect at the time of the generation would be optimal.

ISSUE 2. REVENUE REQUIREMENT

Q. Please discuss Staff's review of the Company's revenue requirement calculations.

A. Regarding Exhibit 107 EIM Revenue Requirement, Staff confirmed that the rate of return the Company applied is consistent with Order No. 12-358[5] and that the income tax methodology is correct. Regarding Idaho Power Exhibit 110 Calculation of Revenue Impact,[6] the calculation in the filed case appears to be consistent with prior filings and conforms to the Minimum Filing Requirements.[7]

Q. Does Staff have any issues with the Company's calculation of the Revenue Requirement?

A. Not at this time.

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[5] *In the Matter of Idaho Power Company General Rate Revision Application for Authority to Increase the Langley Power Plant Investment in Rate Base*, Docket No. 248, Order No. 12-358 (September 30, 2012).

[6] Idaho Power/110, Brady/1.

[7] https://docs.idahopower.com/pdfs/aboutus/ratesregulatory/tariffs/287.pdf.

ISSUE 3. SYSTEM LOAD

Q. Please discuss the Company's calculation of normalized load.

A. Idaho Power's normalized system load included in this year's October Update represents an increase of 14 aMW, or 0.7 percent.[8] The 0.7 percent increase is primarily due to the inclusion of third-party transmission losses into the forecast. Third-party transmission losses represent the additional electricity that Idaho Power generates to offset losses from third parties when they wheel energy through Idaho Power's transmission system. Idaho Power was not previously incorporating this additional load requirement into its load forecast. The Company identified this additional load requirement during a recent line-loss study that determined nearly all wheeling customers participating in the Energy Imbalance Market (EIM) settle their losses financially; meaning Idaho Power must generate the additional energy to account for those losses.

Q. Does Staff have any concerns regarding the Company's inclusion of third-party transmission losses in the calculation of normalized load?

A. In general, Staff does not have concerns with the inclusion of third-party transmission losses. This generation affects IPC's operational decision making and thus should be included in the load forecast.

Q. Does Staff have any concerns regarding how third-party transmission losses are included in the load forecast?

[8] Idaho Power/100, Brady/13.

A. The Company models this load by assuming the forecasted average amount of third-party transmission losses, 36 MW, will be generated in each hour.[9] The Company acknowledges that the actual line loss generation does not occur equally in all hours of the year. The Company asserts that the settlements leading to this generation cannot be predicted in any reasonable way. Although Staff is of the opinion that applying the forecasted average load is a reasonable proxy in their load forecast, Staff would like to see an analysis to determine if the line-loss settlements are truly unpredictable. Staff has discussed using hourly settlement data to attempt to forecast third-party transmission losses, however, the Company responded that a new settlement system had recently been implemented and only one year of data would be available. Staff is of the opinion that one year of data would not be sufficient to derive an empirical pattern of line-loss generation and that a larger sample size would be required. The potential to improve upon the Company's current methodology of applying line-loss generation to the forecast should continue to be evaluated as the data becomes available. Staff recommends that in the Company's next APCU, an analysis looking into the hourly shape of line losses be conducted.

Q. Does Staff have any concerns regarding the methodology used to forecast normalized 2024 load?

A. Staff is currently investigating improvements to the Company's load forecast both in this case and in UE 426 - Idaho Power's General Rate Case. Staff will

[9] Idaho Power/100, Brady/21.

present any proposed adjustments to the load forecast both here and in UE 426, if warranted. At this time, Staff has not formalized any adjustments to the Company's load forecast methodology.

ISSUE 4. RATE SPREAD

Q. Please summarize the methodology used for how rates for the Net Power Supply Expense (NPSE) are spread across customer classes.

A. Idaho Power spreads the $20.9 million APCU revenue requirement on the basis of normalized jurisdictional forecasted sales at the generation level. Parties to Idaho Power's APCU stipulated to this method in 2018,[10] and Idaho Power has used it in each APCU filing since. This methodology also includes a class specific price increase cap to protect against relatively large rate increases to any one schedule. Any rate increases resulting from the application of this methodology as applied to a customer class will be capped at three percent above the overall average rate increase on a percentage of total revenue basis.

Q. Does Staff have concerns with Idaho power's application of the Total Cost Method in the 2021 APCU?

A. Staff has confirmed the calculations given in Exhibit 110 and determined that no class was subject to an increase greater than three percent above the average increase on a percentage of total revenue basis. Staff does not propose any adjustments at this time.

[10] *In the Matter of Idaho Power Company 2018 Annual Power Cost Update,* Docket No. UE 333, Order No. 18-170 (June 13, 2018).

ISSUE 5. JURISDICTIONAL ALLOCATION OF NET POWER SUPPLY EXPENSE

Q. Please discuss the Oregon jurisdictional share of the revenue requirement for the Company's 2024 APCU October update.

A. Oregon's share of the revenue requirement is $20.98 million. The APCU revenue requirement is calculated by adding the 2024 October Update of Oregon jurisdictional share of NPSE of $20.86 million to the Oregon allocated EIM costs of $124,718.

Q. Please summarize the methodology used for allocating the revenue requirement for NPSE across the different states served by IPC.

A. The revenue requirement related to NPSE is spread across Idaho and Oregon in a similar way to how it is allocated to individual customer classes within each state. The Company multiplied the system NPSE total per unit cost of $30.63 per MWh by the forecasted Oregon jurisdictional loss-adjusted normalized sales for the April 2024 through March 2025 test period of 681,006.975 MWH, resulting in an Oregon jurisdictional share of NPSE of $20.86 million.

Q. Does Staff have concerns with Idaho Power's jurisdictional allocation methodology in the 2021 APCU?

A. Staff found no issues with the calculations at this time.

Q. Does this conclude your testimony?

A. Yes

CASE: UE 425
WITNESSES: DAVID ABRAHAM & BRET STEVENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualifications Statement

January 31, 2024

WITNESS QUALIFICATION STATEMENT

NAME: David Abraham

EMPLOYER: Public Utility Commission of Oregon

TITLE: Energy Costs Section Economist
Rates, Safety and Utility Performance Program

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: Master of Science, Economics (2013)
University of Texas,
El Paso, TX

Bachelor of Arts, Business Administration (2005)
University of Texas,
El Paso, TX

EXPERIENCE: I have been employed by the Oregon Public Utility Commission as an economist in the Energy Costs Section since November 2023. Prior to working for the Commission, I worked for an Investor-Owned Regulated Electric Utility in Texas for the past 14 years. I started with the utility as a real-time energy trader and transitioned into the Investor Relations Department as a Financial Analyst in 2012. I moved to a position as an energy and demand forecaster in the Regulatory and Resource Planning Department in 2019 and was named lead-forecaster in May of 2021. I attended an electric utility ratemaking course offered through New Mexico State University and the Center for Public Utilities in 2019.

WITNESS QUALIFICATIONS STATEMENT

NAME:	Bret Stevens
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Rates, Safety, and Utility Performance
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
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EXPERIENCE:	I have been employed at the Public Utility Commission of Oregon since September of 2022. My primary responsibilities revolve around providing research and analysis on rate spread and rate design. I have been a staff witness in UE 407, UE 410, UE 412, UE 414, UE 416, UE 421, and UG 461. Prior to working for the Commission, I was employed by the University of California, Davis as a graduate student researcher, associate instructor, and teaching assistant. I taught courses on econometrics, finance, and microeconomics.