Idaho Power/100
Witness: Jessica G. Brady

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 414

IN THE MATTER OF IDAHO POWER COMPANY'S 2023 ANNUAL POWER COST UPDATE	)
	)
OCTOBER UPDATE	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JESSICA G. BRADY

October 28, 2022

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

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

Q. Please describe your educational background.

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

Q. Please describe your business experience.

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

Prior to Idaho Power, I worked for five years at Clearwater Analytics, a provider of investment accounting and reporting software. I held various roles at Clearwater but was primarily focused on customer success and relationship management. I gained a breadth of knowledge in investments and the use of proprietary software to streamline the operations of a company's finance and accounting teams. I spent my last year at Clearwater developing a training program focused on providing new hires with the technical skills to be successful in an operations role.

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

A. The purpose of my testimony is to present the determination of the Company's 2023 October Update, the first portion of the Company's Annual Power Cost Update ("APCU"). If approved, the 2023 October Update will result in a revenue increase of $3.6 million, or a 6.66 percent increase in base revenue collection, to become effective June 1, 2023.

Q. How is your testimony organized?

A. My testimony begins with a brief history of the APCU and the filing requirements associated with it. Next, my testimony describes the required updates to AURORA and the resulting modeling outputs. I then present and discuss the total NPSE for the 2023 October Update, and how it compares to last year's 2022 October Update. My testimony then discusses the quantification of the projected revenue requirement and the proposed rate implementation to recover the revenue requirement. My testimony concludes with a discussion of additional topics as required by the terms of the settlement stipulation approved in the Company's 2022 APCU filing.

Q. Have you prepared exhibits for this proceeding?

A. Yes. I am sponsoring the following exhibits:

1. Exhibit 101, AURORA modeled determination of normalized power supply expenses for April 1, 2023 – March 31, 2024
2. Exhibits 102 – 104, Mid-Columbia Forward Price Curves Discounted for Inflation, Producer Price Index for Electric Power, and Forward Prices Used for Re-Pricing Purchased Power and Surplus Sales
3. Exhibit 105, Total Normalized Base Power Supply Expenses for the 2023 October Update
4. Exhibit 106, Energy Imbalance Market Benefits
5. Exhibit 107, Energy Imbalance Market Costs

6. Exhibit 108, Year-Over-Year Differences in Modeled NPSE
7. Exhibit 109, Revenue Spread
8. Exhibit 110, Revenue Impact

APCU Overview

Q. What is the APCU?

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

Q. What is the definition of the term "net power supply expense" as the Company and the Public Utility Commission of Oregon ("Commission") have used the term historically?

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

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

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

Q. What is the purpose of the APCU?

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

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

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

Q. What is the AURORA model?

---

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

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

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

AURORA Model Inputs and Modeling Results

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

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

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

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

Coal Fuel Expense

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

A. Yes. Total coal fuel expense included in the 2023 October Update is $82.1 million, compared to $78.8 million in the 2022 October Update, an increase of 4 percent. Coal-fired generation decreased from last year's October Update, from 2.49 million megawatt-hours ("MWh") to 2.46 million MWh, approximately a 1 percent decrease. Forecast generation at Bridger included in the 2023 October Update increased 4 percent from last year's APCU. Forecast generation at Valmy decreased nearly 100 percent.

Q. Were any changes made to how Bridger and Valmy were modeled in AURORA for this year's October Update?

A. Yes. Due to coal supply constraints, which will be discussed later in my testimony, a monthly maximum fuel amount was added to the model in order to align the monthly generation at Bridger and Valmy to the availability of coal within the test year. In order to arrive at the maximum fuel supply on a monthly basis, Idaho Power shaped the annual limit of 1.65 million tons in 2023 and 1.38 million tons in 2024 to ensure the units will operate in months when it is most economical and in accordance with actual expected operations given the limited supply.

In addition, Bridger Units 1 and 2 were modeled as offline beginning January 2024 in preparation for the natural gas conversion that is expected to be complete in June 2024. As a result, only units 3 and 4 are available in the January to March 2024 timeframe.

Q. What factors are driving the forecast coal-fired generation and expenses at Bridger and Valmy?

A. Forecast coal-fired generation at Bridger and Valmy were impacted by fuel supply constraints, which led to an increase in forecast coal prices. Coal prices at Bridger in this year's October Update were $3.224 per MMBtu compared to $2.689 per MMBtu in the 2022 October Update, an increase of 20 percent. Coal prices at Valmy in this year's October Update were $6.071 per MMBtu compared to $2.682 per MMBtu in last year's October Update, an increase of 126 percent.

While coal prices increased from last year's October Update, forward market and natural gas prices have also increased, as will be discussed later in testimony. Due to the coal supply constraints modeled in AURORA at both plants, coal-fired generation was limited in its ability to offset these increases in forward market and natural gas prices.

Q. Please provide additional information on the limited fuel supply and coal price increase at Bridger.

A. The forecast cost of coal at Bridger in this year's APCU increased approximately 20 percent compared to last year due to inflationary cost pressures tied to diesel and other consumables, and also due to increased demand for coal in 2022. Generation at Bridger was higher than expected in 2022, resulting in increased utilization of stockpiled underground coal at Bridger Coal Company ("BCC").

The underground portion of BCC operations was closed at the end of 2021, and the stockpile inventory was originally planned to gradually supplement surface deliveries through the end of 2023. However, with the accelerated use of the coal in 2022, the overall volume at BCC allocated to Bridger in 2023 is 37 percent lower than 2022 levels. The decrease in volume results in the increase of the weighted average cost of coal on a dollar per MMBtu basis. This reduction in expected supply warranted an adjustment to the AURORA model to ensure that modeled generation did not exceed the available supply of coal.

Q. Please provide additional information on the limited fuel supply and coal price increase at Valmy.

A. The forecast cost of coal at Valmy increased approximately 126 percent compared to last year due to the same inflationary cost pressures, as well as limited availability in 2023 from the mines that fuel Valmy. Due to this limited availability, an upper limit was also placed on Valmy within the AURORA model, though as demonstrated in the modeling output, this limit was not reached due to the increased generation costs at this plant.

Q. What circumstances led to the limited coal supply, and what actions are Idaho Power taking to limit customer impact?

A. An increase in natural gas and market prices in 2022 has increased Idaho Power's reliance on coal generation. Actual coal-fired generation for the first 9 months of 2022 is 50 percent higher than the same period in 2021, and 30 percent higher than the 5-year average for the period. To meet the increase in demand for coal-fired generation in 2022, Idaho Power has utilized a significant portion of its stockpile coal inventory and has entered into a new contract for maximum available coal with its third-party supplier Black Butte Coal Company.

The increase in coal-fired generation in 2022, combined with the closure of the underground mine at BCC, has resulted in a limited supply of coal available for use in 2023. Coal supply is expected to improve in 2024, however, when Bridger Units 1 and 2 are converted to natural gas fired units, reducing Idaho Power's coal-fired fleet from 5 units to 3 units.

Idaho Power is working to reduce the impact that the limited coal supply in 2023 will have on customers. At Bridger, Idaho Power plans to use 100 percent of the available production capacity from BCC through 2023. Idaho Power is actively working with its operating partner at BCC, PacifiCorp, to identify opportunities to maximize coal production with existing infrastructure, resources, and equipment. In addition, the Company has secured all available coal from third party suppliers through 2023.

At Valmy, Idaho Power is actively seeking competitive bids for additional coal supply for 2023 and exploring opportunities for Valmy Coal supply for 2024 and 2025. Solicitations made in mid-2022 seeking 2023 coal volumes from spot coal suppliers indicated minimal Western coal available and higher coal prices.

Increasing coal production at BCC to levels that would completely fill the shortfall in supply in the short term would require new permits and additional investment in capital infrastructure. As the coal supply constraints are not expected to persist after the conversion of Bridger Units 1 and 2 to natural gas, additional investment to fill the shortfall in coal supply would not provide a benefit to customers in the long-term.

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

A. The average cost of coal production, on a per-unit basis, for the 2023 October Update is $33.41 per MWh, compared to $31.64 per MWh for the 2022 October Update. At Bridger, the per-unit cost of production increased 7 percent, from $30.12 per MWh in 2022 to $32.15 per MWh in this year's October Update. The per-unit cost of production at Valmy also increased in this year's October Update compared to last year as a result of fixed costs of approximately $3 million being spread over forecast generation of 89.8 MWh.

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

A. Yes. Per the settlement stipulation approved in the 2016 APCU[3], the per-MWh OHAG expense included in the AURORA model has been updated to reflect the amount of OHAG expense driven by Idaho Power's dispatch of the Bridger and Valmy plants. The Company has separately accounted for its proportional share of the total OHAG expense incurred at both plants. Per the settlement stipulation approved in the

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

Company's 2017 APCU[4], Idaho Power's proportional share of total OHAG expense incurred at both of the coal-fired plants is forecast using a three-year historical average of actual OHAG costs, with a growth (reduction) rate equal to the five-year historical average growth (reduction) rate.

Q. Have you prepared an exhibit that illustrates the calculation of OHAG expenses for the 2023 APCU?

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

For example, on Exhibit 101, Line 4 illustrates the AURORA-modeled OHAG expense resulting from Idaho Power's dispatch of Bridger. Line 5 is the difference between the total AURORA-modeled expenses, Line 3, and the AURORA-modeled OHAG expense, Line 4, at Bridger ($84,694.6 + $442.4 = $85,137.0). Line 6 represents the Company's proportional share of total OHAG expenses at Bridger using the stipulated methodology discussed above. Line 7 is the sum of the AURORA-modeled expenses (less the AURORA-modeled OHAG at Bridger, Line 5), and the Company's proportional share of total OHAG, Line 6, ($85,137.0 - $6,111.0 = $79,026). This line reflects the NPSE for Bridger for the 2023 October Update. In this case, calculated OHAG at Bridger reduces total expenses due to proceeds from the

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

sale of combustion fly ash. This method is replicated for Valmy as shown on Lines 9-14.

Q. Does Idaho Power's 2023 APCU account for revenues received from or expenses paid to NV Energy (its ownership partner in Valmy) for usage of the Company's unused capacity or the Company's usage of NV Energy's unused capacity?

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

For the 2023 October Update, the 2019-2021 historical average net revenue paid to Idaho Power associated with NV Energy's dispatch of Idaho Power's unused capacity at Valmy is $112,491 on a system basis. As shown on Line 13 of Exhibit 101, this amount has been reflected as an offset to NPSE for Valmy for the 2023 October Update. The Company will update the three-year historical average as part of the 2023 March Forecast.

Natural Gas Fuel Expense

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

A. Yes. Natural gas expense in this year's October Update is $53.3 million, compared to $55.2 million in 2022, a decrease of 3 percent. Natural gas generation in this year's October Update is 1.13 million MWh compared to 1.79 million MWh in 2022, a decrease of 37 percent.

---

[5] *Id* at 4.

Q. How does the natural gas price forecast for the 2023 October Update compare to last year's October Update?

A. The Henry Hub price used for the 2022 October Update was $3.33 per MMBtu, while the Henry Hub price used in the 2023 October Update is $5.84 per MMBtu, an increase of $2.51 per MMBtu or 75.5 percent.

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

A. The Company uses the gas price forecast for Henry Hub as the starting point in the AURORA model. Henry Hub is considered a reference fuel in AURORA, meaning other gas market prices are determined by applying an adjustment factor to the Henry Hub price. For example, a Henry Hub gas price of $5.84 per MMBtu applied to a Sumas basis of $0.09 per MMBtu equals a Sumas gas price of $5.93 per MMBtu ($5.84 + $0.09 = $5.93). The Company develops a separate gas price for its natural gas units also based upon the Henry Hub gas price forecast, referred to as the Idaho Citygate price.

Q. Please explain the Idaho Citygate price.

A. The Idaho Citygate price is representative of the gas price delivered to Idaho Power's natural gas units. The Idaho Citygate price is based on the Henry Hub price and applies adjustments for Sumas basis and transport costs.

Q. How does the Idaho Citygate price for the 2023 October Update compare to last year?

A. The average Idaho Citygate price for the 2023 October Update is $5.63 per MMBtu compared to $3.94 per MMBtu for the 2022 October Update.

Q. What is driving the increase in the Idaho Citygate price?

A. The increase in the Idaho Citygate price for the 2023 October Update is due to an increase in the Henry Hub price, which is attributable to higher demand for natural gas, increased U.S. liquified natural gas ("LNG") exports, and the war in Ukraine.

Price elasticity of natural gas supply and demand levers has continued to decrease in 2022 as a result of a lack of sufficient gas to coal switching as coal plants are decommissioned. In addition, demand for natural gas has increased due to an increase in electricity demand as a result of extreme weather conditions.

U.S. exports of LNG have also increased since last year. The U.S. became the world's largest LNG exporter in the first half of 2022, according to the U.S. Energy Information Administration. Since the end of 2021, European countries have increased LNG imports to compensate for lower pipeline imports from Russia and low natural gas storage inventories. The war in Ukraine has also caused general volatility and uncertainty in the market, which has led to increases in prices.

The combination of higher demand, increased LNG exports, and volatility surrounding the war in Ukraine is driving the year over year increase in natural gas prices included in the APCU October Update.

PURPA Expense

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

A. Last year's October Update included 347.7 average megawatts ("aMW") of PURPA generation, whereas PURPA generation included in the 2023 October Update is 362.0 aMW, an increase of 14.32 aMW, or 4.12 percent. The increase in PURPA generation is primarily due to normal fluctuations in estimated output from the Company's existing PURPA generation facilities, as well as two new facilities.

Q. Have there been any changes in the number of PURPA projects since last year?

A. The 2023 October Update includes the addition of two new PURPA projects, with executed contracts that are not yet online. They include a 42 MW solar facility and a 30 MW solar facility.

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

A. Annual PURPA expense increased from $237.6 million to $247.3 million, an increase of $9.7 million, or 4 percent. The increase in annual PURPA expense is a result of increased generation and updated PURPA contract values.

New Resources

Q. Have any additional resources been added to the Company's resource portfolio since last year's 2022 October Update?

A. Yes. There are three new resources included in this year's APCU October Update. They include Black Mesa Solar, a 20-year Power Purchase Agreement ("PPA") with Black Mesa Energy, LLC, and two company-owned storage resources. All three resources are scheduled to come online June 2023.

Q. Please explain how the new resources were modeled for the October 2023 filing.

A. Black Mesa Solar is a 40 MW alternating current solar photovoltaic generation facility. The two storage resources include an 80 MW grid battery and a 40 MW battery at Black Mesa Solar. As noted above, all three are scheduled to come online June 2023. However, in order to calculate a "base" or "normal" level of net power supply expense, they are modeled as annualized online resources for the entire test year, reflecting the same treatment applied to new PURPA projects when they are scheduled to come online during an APCU test year. Idaho Power modeled the scheduled generation of each battery so that it shapes to the Company's demand, net of the "must-run" PURPA and PPA resources. As indicative by its name, the 80 MW grid battery can be charged from the entire grid, while the Black Mesa Battery is modeled to only be charged from Black Mesa Solar.

Q. Please explain how Black Mesa Solar's generation and expenses are incorporated into total NPSE and the final NPSE per-unit cost.

A. The Black Mesa Solar PPA was negotiated in conjunction with a new proposed Energy Sales Agreement ("ESA") with Micron Technology, Inc. ("Micron"), a special contract customer located within Idaho Power's Idaho service territory. The Micron ESA states that Idaho Power will procure renewable resources to assist Micron in meeting a portion of its annual energy requirements with energy generated by those resources. While the renewable resource, Black Mesa Solar in this case, will not serve Micron directly, and rather will be connected to the Company's system, Micron will pay for all of the output through its ESA. Because Micron will be paying for 100 percent of Black Mesa Solar's generation, the cost of the PPA is excluded from the Company's calculation of NPSE. In addition, the corresponding portion of forecast sales to Micron are removed from the total customer level sales for the test year. As a result, expenses associated with Black Mesa Solar have been excluded from the final NPSE related Micron sales have been removed from the per-unit cost calculation. In Exhibit 105, Line 18 illustrates the total forecast generation from Black Mesa Solar of 0.098 million MWh and Line 28 shows the total expense of $0. Line 42 illustrates the customer level sales, net of Black Mesa Solar's generation, which is used in the final per-unit cost calculation on Line 43.

Normalized Load

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

A. The Company's normalized system load used in last year's October Update was 1,933 aMW. The Company's normalized system load used in this year's October Update is 1,957 aMW, representing an increase in load of 24 aMW, or 1.2 percent, between the two test periods.

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

A. The Company's 1.2 percent increase in system load is due to continued customer growth in the service area as well as anticipated increased loads from large industrial customers.

Hydro Modeling

Q. Please describe how the hydro modeling changed in the 2022 APCU October Update.

A. Idaho Power adopted new software for the 2022 October Update that replaced the existing modeling tools. The new software is called RiverWare and is an object-oriented, multi-objective river and reservoir modeling decision support system. Unlike the legacy tools, it is widely used, well-funded, and is actively being improved. Idaho Power procured a Snake RiverWare Planning Model, which covers the Snake River Basin from the headwater basins downstream to Brownlee Reservoir inflow, from the U.S. Bureau of Reclamation. Idaho Power also worked with RiverWare developers to develop a model of the Hells Canyon Complex with reservoir operating logic. The RiverWare models simulate reservoir operations, flows at each Idaho Power hydroelectric project, and resulting hydropower production. With the change from the legacy systems to RiverWare, the hydrology period of record ("POR") was also updated to 1951 - 2017 (67 water years). Idaho Power, Commission Staff, and the Citizens' Utility Board convened a workshop prior to the filing of the 2022 APCU to discuss the transition to RiverWare, and the stipulation from that case reflected modeling utilizing this new software.

Q. Were any changes made to the hydro modeling process for this year's APCU?

A. Yes. Forecast hydro generation in this year's October Update is derived from the most recent hydro modeling developed for the 2023 Integrated Resource Plan ("IRP"). This updated modeling effort was performed in 2022 and now includes newly calibrated hydrologic modeling and power generation representation. It also includes a shortened baseline hydrology to include only years after 1980, resulting in 37 water years. As with all IRP modeling efforts, the present conditioning of the water management operating logic was updated to reflect 2022 level management.

Q. Why were these changes made?

A. These changes were identified as part of a systematic review of modeling processes in advance of the 2023 IRP. The resulting updates to the hydro modeling provide an improved representation of observed hydrogeneration and incorporate the Company's best understanding of current and future changes to the distribution of hydropower. The power generation parameters have been refined to account for tailwater effects and reduced generation efficiency under high flow conditions. The shortened baseline hydrology focuses on the most recent years and current hydrologic conditions, while maintaining a sufficient number of years to capture the expected distribution of hydrogeneration. This change also allows the Company to better align with industry standard practices, as other federal and hydro modeling entities use a "30-year normal" analysis period. The hydrologic modeling updates represent an improved calibration of the hydrologic model from a recent recalibration of key cloud seeding basins, which considered only years after 1980. Idaho Power believes these updates result in a hydro modeling methodology that will provide a more accurate expectation of available hydro generation, taking into account industry best practices and better capturing more recent forecast impacts, such as model recalibration and climate change.

Q. Did the Company perform an analysis on how these changes impacted modeling results?

A. Yes. The Company evaluated the overall impact of these updates through a comparison of the 2023-year hydro modeling results from the 2021 IRP to those from the 2023 IRP. The Company also compared how well the updated hydro modeling captures power generation over the observed period in terms of total annual hydropower generation.

Q. What were the results of the analysis?

A. The updated hydro modeling results in an overall decrease in hydro generation compared to previously modeled results. The comparison shows a decline in annual aMW of approximately 8 percent. Comparison to the observed record also shows the updated hydro modeling provides an improved representation of the observed distribution of hydropower generation compared to past IRP assumptions and modeling.

Other

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

A. The Company updated the maintenance rates, forced outage rates, and heat rates for its thermal plants, which is a consistent practice for every APCU filing. The Company also updated the modeled nameplate capacity of Langley Gulch from 300 MW to 336 MW to reflect recent maintenance and thermal upgrades performed at the plant. Lastly, the Company included 11 MW of distribution-connected battery storage in the model.

Q. Please describe the maintenance and thermal performance upgrades that took place at Langley Gulch.

A. The maintenance included replacement of combustors and turbine section components. The thermal performance upgrades included the addition of a rotor cooling system and ultra-low NOx combustors. The ultra-low NOx combustors reduce engine NOx emissions, which in turn reduces consumption of ammonia in the selective catalytic reduction ("SCR") process and reduces the overall load on the SCR catalyst. The increase in thermal performance reduces emission intensity of all pollutants, including greenhouse gases, on a pound per megawatt-hour basis. The resulting impact of these changes is a net increase to generating capacity of approximately 36 MW.

Modeling Results

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

A. Yes. Exhibit 101 shows the results of the AURORA modeling determination of normalized NPSE for the April 2023 through March 2024 test year. Exhibit 101 presents the summary of results containing average variable power supply generation output and expenses based on 37 historical water conditions.

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

A. As can be seen on Exhibit 101, hydro generation supplies 8.37 million MWh, approximately 49 percent (8.37 million MWh / 17.19 million MWh = 49 percent) of the generation mix. Thermal generation supplies 3.58 million MWh (Bridger 2.46, Valmy 0, Langley Gulch 1.04, Danskin 0.05, Bennett Mountain 0.03), approximately 21 percent (3.58 million MWh / 17.19 million MWh = 21 percent) of the generation mix. Purchases of power are made up of short-term and longer-term market purchases, PPAs, and PURPA. PURPA purchases reflect normalized and annualized generation levels and account for 3.18 million MWh. The generation amounts and costs associated with PURPA purchases are not shown on Exhibit 101; however, when combined with market purchases of 2.19 million MWh and PPAs of 0.98 million MWh, total purchases amount to 6.36 million MWh (3.18 million MWh + 2.19 million MWh + 0.98 million MWh = 6.36 million MWh) or approximately 37 percent of the generation mix. Of the 18.29 million MWh generated by the system, 17.19 million MWh are utilized for system loads while 1.10 million MWh are sold as surplus sales.

Base Net Power Supply Expenses

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

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.[6]

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

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

The re-pricing of market prices in the 2023 October Update is based upon the daily forward price curves for April 2024 through March 2025 as shown in Exhibit 102, which were then discounted for inflation back to April 2023 through March 2024 according to the quarterly inflation indices provided in Exhibit 103.

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

A. Yes. In Docket No. UE 384, Idaho Power proposed two adjustments to the re-pricing methodology approved in Order No. 08-238, which were subsequently approved in Order No. 21-165.[7] The Company incorporated both these adjustments to the re-

[6] Order No. 08-238 at 2-3.

[7] *In the Matter of Idaho Power Company's 2021 Annual Power Cost Update*, Docket No. UE 384, Order No. 21-165 (May 27, 2021).

pricing methodology used in this case. The first adjustment eliminated the fixed percentages, as prescribed in Order No. 08-238, used to adjust HL and LL forward prices depending on whether the applicable market energy was purchased or sold. Removing these fixed percentage adjustments results in market energy being re-priced at the established HL or LL forward market prices. The second adjustment relates to the percentages used to determine the portion of AURORA-generated purchased power and surplus sales that occur in HL and LL hours. Historically, these percentages relied on the average of actual purchased power and surplus sales volumes in HL and LL hours for the years 2003-2007. In docket UE 384, Idaho Power updated the percentages based on an average of actual purchased power and surplus sales volumes in HL and LL hours for the years 2016 – 2020. The Company updated these percentages in this year's October update to incorporate data from 2017 – 2021.

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

A. Exhibit 104 shows the monthly prices that are used for the re-pricing of purchased power and surplus sales volumes for the 2023 October Update. The prices range from a low of $22.40 per MWh to a high of $112.14 per MWh.

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

A. Lines 32 and 43 of Exhibit 101 show the purchased power expenses and surplus sales revenues, respectively, as determined by the AURORA modeling process. Lines 23 and 34 of Exhibit 105 show the same normalized generation dispatch with purchased power and surplus sales re-priced using the normalized forward price curve shown in Exhibit 104. A comparison of Exhibit 101 and Exhibit 105 demonstrates the changes due to re-pricing. Purchased power expenses increased by $45.9 million, moving from

$88.3 million to $134.2 million. Surplus sales revenues increased by $10.5 million, moving from $39.0 million to $49.5 million. In this case, the NPSE resulting from the re-pricing methodology shown on Exhibit 105 is an increase in NPSE of $35.4 million as compared to the AURORA-generated expectation shown on Exhibit 101. The differences for the re-pricing of purchased power of $45.9 million and surplus sales of $10.5 million are shown on Exhibit 108, Column J.

Energy Imbalance Market ("EIM") Benefits and Costs

Q. Has the Company adjusted the NPSE amounts included in the 2023 October Update to reflect Idaho Power's participation in the Western EIM?

A. Yes. The NPSE requested for approval in the 2023 October Update includes both the incremental benefits and costs associated with Idaho Power's participation in the Western EIM. This treatment is consistent with the methodology approved by the Commission in Idaho Power's 2018 - 2022 APCU dockets, Docket Nos. UE 333, UE 350, UE 366, and UE 384 in Order Nos. 18-170, 19-189, 20-164, and 21-165.

Q. What level of EIM benefits is Idaho Power proposing to include in the 2023 October Update?

A. For the 2023 October Update, Idaho Power has used the EIM benefits reflected in the stipulated results from the 2022 October Update, which is $25.2 million at the system level and $1.1 million on an Oregon allocated basis. Due to fluctuations in California Independent System Operator's ("CAISO") benefit data for this year, resulting in almost half the stated benefits from last year, the Company has elected to use the stipulated benefit amount from the 2022 October Update until the values from CAISO can be confirmed. Idaho Power is currently in the process of examining and validating the benefits quantified by CAISO and expects to apply any update to this amount in the March forecast.

Q. How did the Company determine the level of EIM benefits to be included in the 2023 October Update?

A. The level of EIM benefits to be included in the 2023 October Update utilizes the amount quantified for the 2022 October Update, which used the CAISO report of EIM benefits, for February 2021 through January 2022, as a starting point, and then accounted for a necessary adjustment to quantify ongoing cost savings benefits specific to Idaho Power's participation in the EIM. This adjustment reflects a modification to the CAISO methodology as it pertains to the hydro pricing cost structure, further detailed later in my testimony.

Q. How does CAISO quantify EIM benefits?

A. CAISO uses a counterfactual methodology in which dispatch for an EIM Balancing Authority Area ("BAA") mimics market operations without importing or exporting through EIM transfers. The counterfactual dispatch moves units inside the BAA to meet real-time imbalance based on economic merit order. CAISO's quantification of total estimated EIM benefits is the cost savings of the EIM dispatch compared to the counterfactual without EIM dispatch. In order to determine both EIM dispatch costs and counterfactual costs, CAISO relies upon bid prices submitted by EIM entities.

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

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

Idaho Power bids hydro resources based on an operational need rather than actual dispatch cost. Additionally, Idaho Power utilizes various pricing tiers for its hydro resources to protect the water from overuse in the market and to adhere to regulated water management requirements.[8] The pricing tiers that Idaho Power uses are based upon certain operational parameters and can result in high bid prices when it is necessary to cease or limit water flows for a particular hydro resource's market participation. When Idaho Power operators move water into the higher tiers, which have a higher bid price, it is a response to operational needs and does not reflect market benefits.

Without adjusting for these operating scenarios, CAISO's EIM benefit methodology incorrectly reflects the bid tier price as the economic value of hydro in the determination of both counterfactual costs and EIM dispatch costs, thereby overstating the resulting benefits. In order for the EIM benefit calculation to properly serve as an adjustment to modeled NPSE, Idaho Power made adjustments to the CAISO methodology as it pertains to the hydro pricing cost structure.

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

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

[8] Requirements may include flood control obligations, fish flow obligations, etc.

Holding the dispatch costs constant by applying a zero-cost also satisfies a correction to the EIM dispatch costs. The EIM is not a capacity market. Therefore, in a hydro system with limited ability to store water long-term, EIM imports (or the dispatching down and storage of the water) will have matching exports over a given time period (that hydrogeneration will be exported soon thereafter). When EIM hydro imports match exports over a measured period, in the case of Idaho Power's analysis an hourly basis,[9] dispatch costs should be held constant by replacing all tier prices with a zero cost. In this scenario, the actual benefit is the difference between the EIM import and export price. If the EIM dispatch cost is not held constant over the measured period, it results in an inaccurate benefit.

However, when hydro imports do not equal exports, it is necessary to value, or assign a cost to, the net import / exports to the market. This is the second part of the adjustment Idaho Power made to the hydro pricing cost structure as it pertains to the EIM benefit calculation.

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

A. When imports exceed exports during the measured period, using a zero-cost value will underestimate benefits because it does not properly account for the value of imported energy that serves load (rather than hydro) and provides a benefit to the Company's customers. Conversely, when exports exceed imports during the measured period, the zero-cost value will inflate benefits because there aren't any costs assigned to the hydrogeneration that was moved into the market. In either scenario, the net imports / exports for the hydro resources will show a benefit at the

[9] The adjustments to the hydro pricing cost structure for the EIM benefit calculation are performed on an hourly basis at the recommendation of OPUC Staff. *In the Matter of Idaho Power Company's 2020 Annual Power Cost Update*, Docket No. UE 366, Idaho Power/300, Blackwell/17-18 (March 24, 2020).

EIM Locational Marginal Price ("LMP") because there are no costs associated with the hydro dispatches. As a result, it is necessary to make a second adjustment to the EIM benefit calculation to properly account for the hydro cost when imports do not equal exports for the measured period.

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

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

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

A. Yes. Exhibit 106 demonstrates Idaho Power's adjustments to the CAISO EIM benefit methodology as it pertains to the hydro pricing cost structure for the full 12-month period. Column A of Exhibit 106/1 includes CAISO's reported benefits for Idaho Power for February 2021 – January 2022 of $53.3 million. Column B illustrates Idaho Power's application of a zero-cost for all hydro tier prices when EIM imports equal exports on an hourly basis. This adjustment resulted in an EIM benefit of $21.4 million, a $31.9 million reduction from CAISO's stated EIM benefits for Idaho Power.

Column C of Exhibit 106/1 demonstrates the adjustment to the hourly net import / export position for the hydro resources. As discussed previously, Idaho Power assigned a value to the net import / export position for each hour based on the

Powerdex Mid-C market electricity price. This adjustment resulted in a $3.8 million increase to Idaho Power's EIM benefit estimate.

Q. Please summarize the final estimate of EIM benefits to be included in the 2023 APCU.

A. Due to fluctuations in CAISO's benefit data for this year, resulting in almost half the stated benefits from last year, the Company has elected to use the stipulated benefit amount from the 2022 October Update until the values from CAISO can be confirmed. The EIM benefits forecast is based on the CAISO's EIM benefits reports, with necessary adjustments for hydro pricing as described in this testimony. As detailed in Exhibit 106, the estimated system benefit is $25.2 million, or $1.1 million on an Oregon jurisdictional basis. The Company has included the estimate of EIM benefits as an offset to forecast NPSE for the October Update as shown in Exhibit 105.

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

A. As stated previously, by participating in the Western EIM, the Company achieves NPSE savings, which benefit customers; however, to achieve such benefits, Idaho Power has incurred, and will continue to incur, incremental costs to participate in the Western EIM, including software and metering investments and annual, ongoing operations and maintenance ("O&M") expenses. Consistent with the 2021 and 2022 APCU dockets, the Company has included EIM-related costs in the 2023 APCU. The EIM-related costs included in the 2023 October Update consist of the annual return on net rate base from the capital investment required to participate in the Western EIM, depreciation expense, and ongoing O&M expenses. On an Oregon allocated basis, the revenue requirement associated with EIM costs to be included in the 2023 October Update is $114,672, as shown in Exhibit No. 107.

Per-Unit Cost Calculation and NPSE Discussion

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

A. Exhibit 105 shows total system NPSE of $497.8 million and normalized annual sales at the customer level for the April 2023 through March 2024 test year, net of Black Mesa Solar's generation, of 15,739,156 MWh, resulting in a per-unit cost for the 2023 October Update of $31.63 per MWh ($497.8 million / 15.739 million MWh = $31.63 per MWh) to become effective on June 1, 2023.

Q. How does the 2023 October Update per-unit cost of $32.42 per MWh compare to the 2022 October Update per-unit cost?

A. The 2022 October Update per-unit cost, which became effective June 1, 2022, was $26.46 per MWh based upon a determination of total NPSE of $413.7 million

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

A. Yes, Exhibit 108 compares the AURORA-developed results, the re-pricing of purchased power and surplus sales, and the differences between the 2022 October Update and the 2023 October Update. Column H of Exhibit 108 shows the following: (1) An increase in coal expenses of $3.3 million associated with an decrease of 0.03 million MWh in generation, (2) a decrease in natural gas expenses of $1.9 million associated with a decrease of 0.67 million MWh in generation, (3) an increase in market purchased power expenses of $96.0 million associated with an increase of 1.25 million MWh, (4) a decrease in PPA expenses of $0.8 million associated with an increase of 0.13 million MWh, (5) an increase in PURPA expenses of $9.7 million associated with an increase of 0.13 million MWh, and finally, (6) an increase in surplus sales revenue of $21.5 million associated with a decrease of 0.15 million MWh.

Q. Can you elaborate more on the changes in generation from the 2022 October Update to the 2023 October Update?

A. To illustrate the changes in generation, Columns D (2022) and F (2023) of Exhibit 108 calculate the percentage of generation compared to total system load. For example, Column F, line 1, shows that hydro provided 49 percent of the generation to meet the total system load of 17,188,548 MWh (8,373,292 / 17,188,548 = 49 percent) compared to 54 percent in the 2022 October Update. Coal generation decreased from 15 percent to 14 percent, natural gas generation decreased from 11 percent to 7 percent, market purchased power increased from 6 percent to 13 percent, PPA generation increased from 5 percent to 6 percent, PURPA generation increased from 18 percent to 19 percent, and lastly, surplus sales decreased from 7 percent to 6 percent. This comparison between resource type and total system load shows that reduced hydro and natural gas generation is being met with increased market purchases.

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

A. Yes. The changes in expenses among resource types are relatively consistent with the changes in output, especially when taking into account the changes in the per-unit cost of the various resources. The changes in expenses for each resource type are also shown in Columns D (2022) and F (2023) of Exhibit 108 as follows: Coal expense decreased from 19 percent to 16 percent of total NPSE, natural gas expense decreased from 13 percent to 11 percent, market purchased power expense increased from 9 percent to 27 percent, PPA expense decreased from 14 percent to 11 percent, PURPA expense decreased from 57 percent to 50 percent, and surplus sales revenue increased from 7 percent to 10 percent. Exhibit 108 demonstrates that the majority of movement in NPSE is related to increases in market purchased power expense.

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

A. The information shown in Exhibit 108 confirms that the 8 percent decrease in hydro generation combined with the 37 percent decrease in natural gas generation are being met with a 133 percent increase in forecast market purchases from last year's October Update.

Q. Did the Company comply with the methodology in Order No. 08-238 when it performed its analysis to determine the NPSE for the 2023 October Update?

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

Jurisdictional Allocation of NPSE

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

A. The Oregon jurisdictional share of NPSE is calculated by multiplying the system NPSE total per-unit cost of $31.63 per MWh by the forecasted Oregon jurisdictional loss-adjusted normalized sales for the April 2023 through March 2024 test period of 703,784.157 MWh, resulting in an Oregon jurisdictional share of NPSE of $22.3 million ($31.63 x 703,784.157 MWh = $22.3 million), as shown on Line 1 of Exhibit 109.

Quantification and Discussion of the APCU Revenue Requirement

Q. Based on the determination of the Oregon jurisdictional share of NPSE, what is the APCU revenue requirement for the 2023 October Update?

A. As shown on Line 3 of Exhibit 109, the APCU revenue requirement is $22.4 million. The APCU revenue requirement is calculated by adding the 2023 October Update Oregon jurisdictional share of NPSE of $22.3 million, Line 1, to the Oregon allocated EIM costs of $114,672 Line 2.

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

A. Exhibit 109 also reveals the revenue impact resulting from this year's October Update. As shown on Line 12, base NPSE recovery under current approved APCU rates is

$18.8 million, whereas the proposed 2023 APCU October Update revenue requirement is $22.4 million, as shown on Line 3. The comparison of this year's October Update to current approved revenue indicates an increase in Oregon customer rates of $3.6 million.

Rate Implementation

Q. What method of allocation did the Company use to spread the APCU revenue requirement associated with the 2023 October Update to the various customer classes?

A. The Company allocated the $22.4 million APCU revenue requirement associated with the 2023 October Update using the revenue spread methodology agreed upon in the settlement stipulation approved by Order No. 18-170.[10] Order No. 18-170 established a revenue spread methodology whereby the total APCU revenue requirement is allocated to individual customer classes on the basis of normalized jurisdictional forecasted sales at the generation level for the test period. It should also be noted that the agreed upon revenue spread methodology included a provision that any rate increases resulting from application of this new methodology as applied to a customer class would be capped at 3 percent above the overall average rate increase on a percentage of total revenue basis. This cap was implemented to recognize that the movement to the new methodology could result in relatively large increases for individual classes within a single year. The cap is not applicable for the 2023 APCU.

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

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

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

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

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

Q. Does the Company intend to provide supporting workpapers for the 2023 October Update to Staff and CUB?

A. Yes. Idaho Power will provide its supporting workpapers to Staff and CUB as part of the 2023 APCU filing. The Company intends to provide these workpapers within five business days of filing the 2023 APCU.

<u>Compliance with the 2022 APCU Settlement Stipulation</u>

Q. Did the settlement stipulation approved in the Company's 2022 APCU result in the requirement for the Company to address any additional topics in the 2023 APCU filing?

A. Yes. The settlement stipulation required the Company to discuss two topics in opening testimony in the 2023 APCU filing: 1) energy markets and related transactions, and 2) opportunities related to the Infrastructure Investments and Jobs Act ("IIJA").

Q. Please describe the component of the 2022 APCU settlement stipulation related to markets and related transactions.

A. As part of the 2022 APCU settlement stipulation, parties agreed that Idaho Power would discuss the energy market landscape and how it has changed over the last 10 years. The discussion should include changes in market and wheeling transactions and how the Company's APCU forecasted market transactions corresponds with actual operations.

Q. Please describe Idaho Power's current market landscape and how it has changed over the last 10 years.

A. Idaho Power has transmission connections, transmission rights, and the potential to purchase additional transmission capacity that provide it access to power markets in the Pacific Northwest (Mid-Columbia) as well as in the Desert Southwest (for example, Four Corners; Mead; Palo Verde). Idaho Power can take delivery of purchased energy at these market hubs or at its border. Idaho Power has purchased long-term transmission rights with which to import energy purchased off-system, and regularly purchases additional short-term firm or non-firm transmission for that purpose.

Over the past several years the bulk of Idaho Power's energy purchases to serve load have been delivered to Idaho Power at the Mid-C hub. Idaho Power then uses third-party transmission to import that generation to its system to serve load. Historically, Idaho Power was able to obtain short-term firm transmission with which to import that energy. Over the past few years, and particularly since 2020, the Company began to see firm transmission capacity on third-party systems becoming scarce. Other entities were seeking that same capacity on third party systems to move power from the Pacific Northwest to other locations.

As a result of this growing scarcity of firm transmission rights on neighboring transmission systems, Idaho Power’s load serving operations department entered into agreements to purchase long-term firm transmission capacity on third party transmission systems when it was available and when there was a need for it to serve the Company’s load, particularly in peak summer months. Idaho Power had one 100 MW reservation commence in 2021, another in 2022, and an 80 MW reservation will commence in 2023, in addition to other smaller reservations that were already in place. These transmission reservations provide access to primarily the Mid-C market and Northwest counterparties, although Idaho Power also has 50 MW of firm transmission from the south. These reservations are a critical component of Idaho Power's resource stack, contributing to Idaho Power's ability to reliably serve load, particularly as other resources have ceased operation (for example, North Valmy Unit 1 and Boardman).

In this same post summer 2020 timeframe, Idaho Power saw a significant increase in third-party entities seeking transmission service to move power across Idaho Power's system to other locations. Idaho Power has seen increased requests for long-term firm point-to-point, which led to additional sales of firm point-to-point service. Table 1 shows the increase in point-to-point sales over the last 10 years.

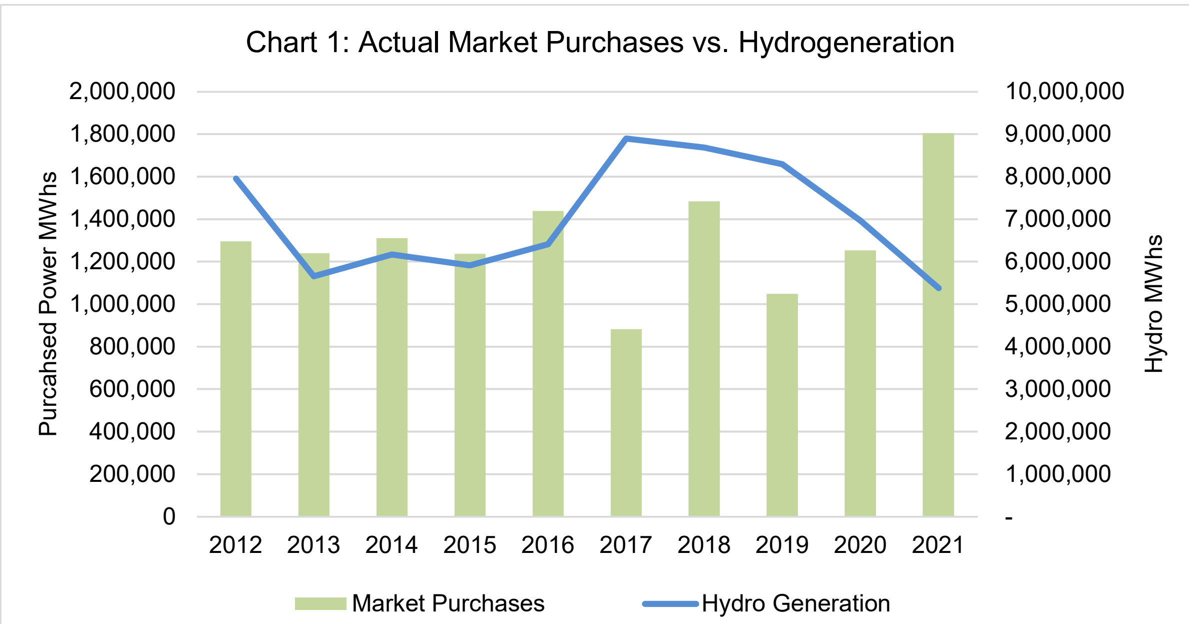
Table 1	**Point-to-Point Wheeling Volume**	
Line No.	Year	Volume (MWh)
1	2012	7,706,572
2	2013	7,799,186
3	2014	7,729,398
4	2015	8,359,499
5	2016	9,654,563
6	2017	11,456,839
7	2018	12,148,531
8	2019	11,341,490
9	2020	12,308,920
10	2021	14,562,515

In addition, monthly non-firm transmission demand has increased for the summer months as others look to move power from the pacific northwest to the desert southwest or California. Lastly, Idaho Power's short-term transmission sales to third parties have increased due to price spreads between the northwest and southwest market hubs that create additional demand for service across the Company's transmission system to move energy from one market to the other.

Q. How have the market changes described above impacted market transactions?

A. While these changes in the transmission landscape were occurring, Idaho Power also implemented changes in its resource stack. Idaho Power exited participation in North Valmy Unit 1 at the end of 2019, and Boardman ceased operation in October 2020.

Idaho Power’s significant hydroelectric generation fleet provides the benefit of low-cost, dispatchable, clean energy for customers. However, variations from year-to-year in the water supply can have an impact on generating capability. The reduction of capacity from North Valmy Unit 1 and Boardman, and the variability in water supply conditions, can lead to Idaho Power procuring more energy from the market than it had in the past. Chart 1 shows total hydrogeneration and market purchases for the last 10 years. As demonstrated by this figure, the amount of market purchases has an inverse relationship with the level of hydro generation availability.



Q. How has Idaho Power’s entrance into the Western Energy Imbalance Market changed the energy market landscape?

A. Idaho Power's entrance into the Western Energy Imbalance Market has not materially changed the discussed transmission rights or the transmission and day-ahead energy market landscape because each participant much enter each hour balanced Therefore, Idaho Power still makes use of its transmission rights by scheduling energy on a day-ahead basis. EIM transfers on the operating day rely on transmission that has not been scheduled before the operating hour, and the EIM does not remove the transmission from others who may want to procure it for bi-lateral use. However, actual market transaction volumes have increased due to sub-hourly transactions within the EIM.

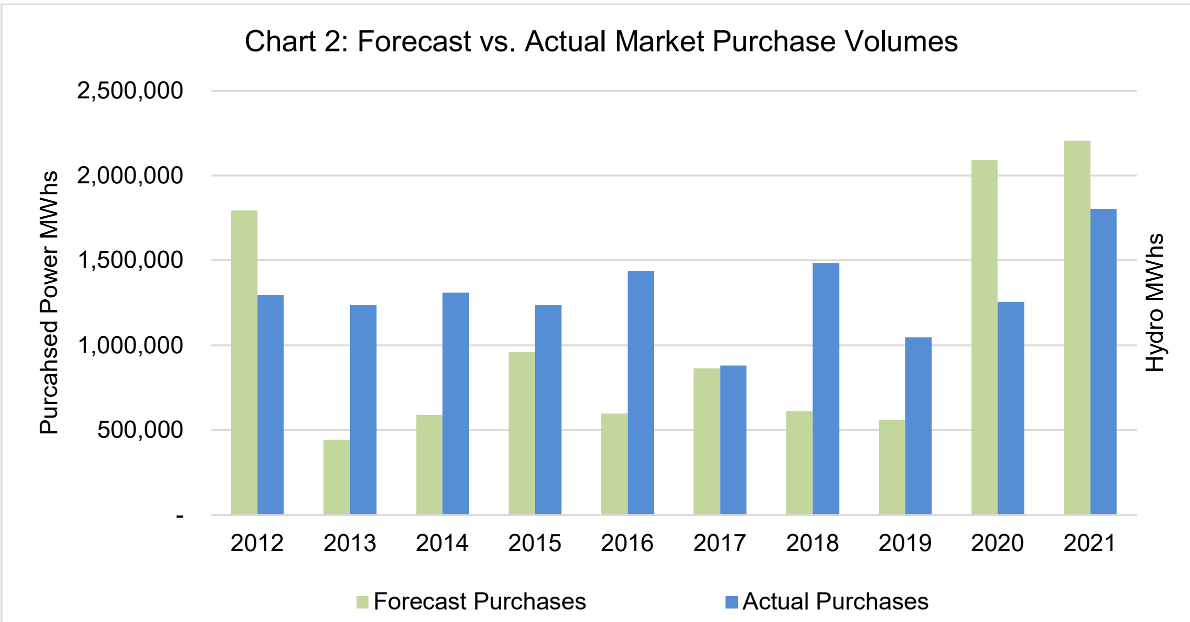
Q. How is the energy market modeled within AURORA for the APCU?

A. AURORA models electricity prices in a wholesale energy market where prices are based on the marginal cost of production (prices rise to match the variable cost of the last generating unit in each zone needed to meet demand). The energy market, in this case the Western Interconnection, is mapped out into distinct zones that contain the respective balancing authorities and resources. Transmission lines are set up between zones and modelled with a capacity limit, line loss percentage, and wheeling rate.

In order to simulate the economic dispatch of resources within each zone, AURORA considers economics and physical characteristics of supply and demand, including hourly demand, resource operating characteristics, and transmission constraints. In determining the least cost system NPSE for Idaho Power, AURORA determines which resource is the most economical in any given hour (that meets the demand and resource constraints). In order for a market purchase to be considered economical, AURORA first ensures transmission capacity is available, and then considers wheeling rates and line losses associated with delivery. Once all constraints are considered, including transmission constraints, if a market purchase is the most economical in that hour, then AURORA will select it. The same analysis occurs when determining the economics of off-system sales.

Q. How have forecast transactions in the APCU compared to actual market transactions?

A. The calculated marginal cost of production in Idaho Power's zone is largely based on input hydro conditions, fuel prices, and other resource characteristics. AURORA considers these inputs and comes up with an optimal solution that minimizes total cost while considering the given constraints. To the extent that actual market factors differ from modeled inputs, actual generation mix and expenses will be different from forecast. Chart 2 shows the comparison of forecast versus actual market purchases over the last 10 years.



The Company evaluated these differences between forecast market transactions and actual transactions and found that the differences were generally a result of multiple factors that differed on an actuals basis relative to the expectations input into the AURORA model. These factors include, but were not limited to, different than expected hydro conditions, higher than anticipated peak loads, and higher or lower gas and coal prices. Based on the Company's review, differences between modeled and actual results were justifiable given the differences between inputs to the AURORA model and actual conditions that occurred throughout the test year. The Company's review indicated that the AURORA model is appropriately structured to accurately model market transactions based on current transmission and generation capabilities as well as expected conditions when the forecast is developed.

Q. Please describe the component of the 2022 APCU settlement stipulation related to the Investment Infrastructure and Jobs Act.

A. As part of the 2022 APCU settlement, parties agreed that Idaho Power would discuss whether and how the Investment Infrastructure and Jobs Act ("IIJA") may bring about benefits to Idaho Power customers. The discussion should include funding for hydropower and transmission projects, and funding allocated to specific states.

Q. Please discuss the projects or initiatives that Idaho Power is working on or has identified as a priority for IIJA funding.

A. Idaho Power has a project team dedicated to identifying applicable funding opportunities available through the Investment Infrastructure and Jobs Act. Each IIJA grant or program is vetted with subject matter experts to determine whether it could be used for a project or initiative that would benefit customers and be practical for the Company to pursue. Currently, six projects or initiatives have been identified as a priority for IIJA funding: grid modernization, Gateway West capacity contracts, wildfire mitigation infrastructure, dam infrastructure and safety, transmission builds, and electric vehicle charging infrastructure. Most of these initiatives are in initial phases, as the majority of grant applications open in Q4 of 2022 or in 2023.

Many of these initiatives, including grid modernization, wildfire mitigation infrastructure, and transmission builds, have been identified as potential candidates for federal funding from the Grid Resilience and Innovation Partnership ("GRIP") grant program or state funding through the Preventing Outages and Enhancing the Resilience of the Electric Grid formula grant program ("Formula Grant Program"). The GRIP program was established in sections 40107, 40101(c), and 40103(b) of the IIJA, and includes $10.5 billion in federal funding over 5 years. Idaho Power is currently participating in the request for information ("RFI") from the Department of Energy ("DOE"), Grid Deployment Office. The Formula Grant Program was established in section 40101(d) of the IIJA and is allocated $2.3 billion nationally, with $50 million being allocated to Oregon.

Idaho Power continues to partner with the State of Oregon and State of Idaho as they prepare their response to the DOE due March 31, 2023. The remaining grants in the GRIP program are not yet open for application, but Idaho Power is monitoring them closely and actively participating in related discussions and RFIs.

Section 40106 of the IIJA establishes the Transmission Facilitation Program ("TFP"), which has been identified as the potential funding source for the Gateway West capacity contracts initiative. The TFP, with a total of $2.5 billion in federal funding, is designed to facilitate the construction of transmission lines and related facilities to enable clean energy growth and lower the costs of clean energy. Idaho Power is currently participating in the DOE's RFI process for this program.

Sections 40332 and 40333 establish incentives to make hydroelectric efficiency and safety improvements. Idaho Power has submitted its RFI comments to the DOE and is currently evaluating applicable projects.

There are multiple programs established within the IIJA that will provide funding for electric vehicles ("EV") and charging infrastructure. One of those is the National Electric Vehicle Infrastructure Program ("NEVI"). The primary goal of the NEVI program is to increase access to EV charging with new or improved direct current fast charging stations along designated alternative fuel corridors. In Idaho Power's Oregon service area, four highways have been identified for NEVI funding over the next five years. NEVI funding is allocated to states; therefore, Idaho Power will not be a direct recipient of any funds in this program. Other programs that will provide funding for electric vehicle infrastructure include the Clean School Bus Program (eligible to school districts), the Discretionary Grants for Charging and Fueling Infrastructure (eligible to state and local governments), and the Low or No Emission Vehicle Program (eligible to state and local governments). Idaho Power continues to provide support and expertise to program applicants and recipients for these programs.

Q. Does this conclude your testimony?

A. Yes, it does.