Oregon
Kate Brown, Governor

Public Utility Commission
201 High St SE Suite 100
Salem, OR 97301
Mailing Address: PO Box 1088
Salem, OR 97308-1088
Consumer Services
1-800-522-2404
Local: 503-378-6600
Administrative Services
503-373-7394

February 4, 2020

Via Electronic Filing

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

UE 366: In the Matter of IDAHO POWER COMPANY,
2020 Annual Power Cost Update.

Enclosed for electronic filing are Certificate of Service, UE 366 Service List and the following exhibits:

Exhibits 100 to 101: Exhibit 100 pages 16, 19, 20 & 21 are confidential. Two confidential work paper are filed in electronic format

Exhibits 200 to 203: Exhibit 200 pages 7 & 8 and Exhibit 203 are confidential.

Exhibits 300 to 302 and

Exhibits 400 to 404: Exhibit 400 pages 7, 8, 10 & 12 are confidential. Exhibits 403 and 404 are confidential and filed in electronic format.

Certificate of Service and Service lists are included with this filing. A packet containing confidential material is being overnighted to parties who have signed Protective order No. 19-379.

/s/ Kay Barnes
Kay Barnes
PUC- Utility Program
(503) 378-5763
kay.barnes@state.or.us

CASE: UE 366
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

February 4, 2020

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

A. My name is Moya Enright. I am a Senior Utility and Energy Analyst employed in the Energy Rates Finance and Audit Division 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, Company or IPC) 2020 Automatic Power Cost Update filing (APCU), the proposed revenue impact, and Staff's proposed adjustments. I then discuss the Company's forecast of benefits from its participation in the CAISO Energy Imbalance Market (EIM). Finally, I summarize Staff's review of the calculations for new rates stemming from the APCU, including the Net Power Supply Expense (NPSE) and rate spread calculations.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Did you prepare an exhibit for this docket?

A. Yes, I have prepared the following exhibits:

1. Exhibit 101, Witness Qualification Statement.

OVERVIEW OF FILING

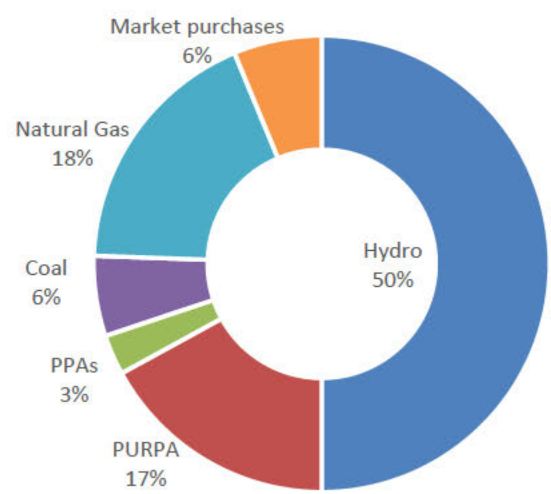
Q. Please summarize the revenue impact of Idaho Power's 2020 Annual Power Cost Update (APCU) filing.

A. The Company filed its forecasted power costs for the April 2020 through March 2021 test year on October 31, 2019. In its filing, the Company proposes a revenue decrease of $176,943, or 0.32 percent, which if approved would take effect on June 1, 2020.

Q. What is driving this reduction in rates?

A. The driver of this change is a forecasted 41 percent reduction in coal-fired generation, and 37 percent fall in coal generation costs. This change comes as the Boardman Coal Plant Boardman (Boardman) is retired in late 2020,[1]

Figure 1 - Forecasted 2020 Generation by Fuel Type



The Company also ceases operations at one of its two units at the coal-fired North Valmy Generating Station (Valmy Unit 1) in late 2019,[2] and the availability of low prices market purchases makes the coal-fired Jim Bridger Plant (Bridger) less economic to run.[3] Natural gas generation is also

---

1 Idaho Power owns a ten percent share of Boardman. Portland General Electric owns the majority 90 percent share of the plant.

2 Idaho Power (and co-owner NV Energy) agreed to end its participation in Valmy Unit 1 by Dec. 31, 2019, and in Valmy Unit 2 by Dec. 31, 2025. See: www.idahopower.com/news/idaho-power-finalizes-agreement-to-cease-participation-in-operations-at-valmy-coal-fired-plant.

3 Idaho Power/100, Blackwell/5, lines 21 and 22.

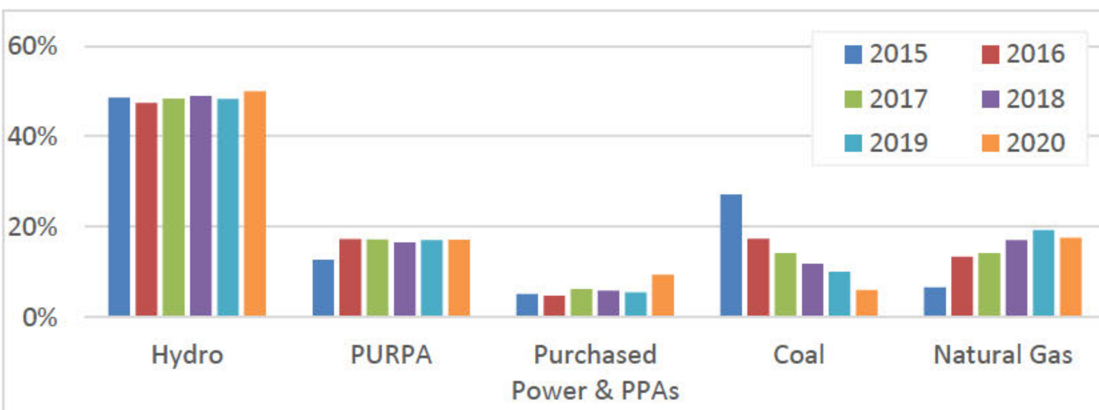
forecasted to decrease by nine percent in the test year, with natural gas generation costs forecasted to fall by 13 percent. The Company's forecasted fuel mix is shown in Figure 1.

The decrease in coal and natural gas fired generation is offset by a three percent increase in hydro generation and a 70 percent increase in market purchases.

Staff has observed a trend of lower forecasted coal fired generation, and increased market purchases in recent years, as illustrated in Figure 2. Such a shift may be expected to continue in future years as the Company works toward achieving its goal of 100 percent clean energy by 2045.[4]

Figure 2 - Generation mix 2015 - 2020 (per October Update forecast)

[5]



Q. Are further updates expected in the docket?

A. Yes. The APCU is a two-part filing. In its initial filing, the "October Update", the Company has presented its forecast of power supply expenses for the 2020 test year. The October Update is a forecast of the Company's power cost based on

---

4 See: www.idahopower.com/news/idaho-power-sets-goal-for-100-percent-clean-energy-by-2045.

5 UE 301, Idaho Power/106, Noe/1; UE 333, Idaho Power/107, Blackwell 1; UE 366, Idaho Power/108, Blackwell 1.

historical water conditions, and if approved, the October Update is reflected in updated base rates.

In the second part of the Company's filing, the "March Forecast",[6] the Company will use a hydro forecast with water conditions specific to the test year to provide an updated power cost forecast. NPSE changes relating to the 2020 water conditions forecast will be reflected in the March Forecast rate adjustment.

In addition to using an updated water conditions forecast, the March Forecast will provide an updated EIM benefits forecast using data from Quarter 4 2019, and will reflect the most recent updates to the following variables: fuel prices and transportation costs, wheeling expenses, planned and forced outages, heat rates, forecasted sales and loads, wholesale power purchase and sales contracts, forward price curve, PURPA expenses, and the Oregon state allocation factor.

Staff's opening testimony relates to the Company's 2020 October Update only. Staff will provide further testimony once the March Forecast has been filed and reviewed.

Q. What aspects of the APCU filing has Staff reviewed?

A. Staff has carried out a thorough investigation of IDP's filing, including but not limited to reviewing the Company's calculations and methodology, reviewing historical data and past forecasts, and investigating the models proposed by the Company.

[6] The March Forecast will be filed on March 24, 2020.

The following issues will be dealt with in detail in Staff's testimony:

Staff/100	Energy Imbalance Market
	Net Power Supply Expenses (NPSE) and Rate Spread
Staff/200	AURORA Re-Pricing
	Bridger Coal Company Depreciation
	Valmy Unused Capacity
	Boardman Operations 2020
Staff/300	Allocation
	Fuel Prices
	Oil, Handling, Administrative, and General (OHAG) Expenses
	Wholesale Purchases and Sales
	Load and Sales Forecast
Staff/400	Wheeling
	Forced outage rates and Scheduled maintenance outages
	PURPA
	Heat rates
	Wind Forecast
	Solar Forecast/Shape

Q. Has Staff proposed any adjustments to the company's 2020 APCU filing?

A. Yes, Staff proposes the following adjustments:

EIM Benefits Increase of $5.0 million, reflecting Staff's recommendation to use the Mid-C mid-market price and

	hourly data in the Company's "Hydro Net Export/Import Adjustment", and to include an annual growth factor of 22 percent in the forecast.
Boardman Operations 2020	Staff recommends that the Company track any benefits arising from Boardman being dispatched after its forecasted closure date of October 31, 2020, with any realized value being included as an offset to NPSE in the 2022 APCU. The 2022 APCU will be the first power cost update filing following the scheduled closure of Boardman.
OHAG expenses	Staff identified a shortcoming in the agreed upon methodology for calculating OHAG expenses, as applied to Valmy Unit 1, given Company's arrangement to cease its operations at the plant. Staff will continue to work with the Company to identify the appropriate OHAG expense in reply testimony, accounting for the Company's obligations under the terms of the Framework Agreement with NV Energy.[7]
PURPA expenses	Decrease of $29.06 million, which is intended to correct for a consistent over-forecasting of PURPA costs in

[7] The North Valmy Project Framework Agreement between NV Energy and Idaho Power allowed the Company to cease operations at Valmy Unit 1, while its partner continues to operate the unit.

recent years. This adjustment is calculated as a 13 percent reduction to PURPA expenses.

Q. What is the effect of Staff's proposed adjustments on rates?

A. Staff has calculated that Staff's EIM benefit and PURPA adjustments will reduce the Company's NPSE from $25.10 per MWh to $22.83 per MWh. On an Oregon allocated basis, this constitutes a $1.6 million reduction in the Company's revenue requirement.

Staff notes that this estimate is subject to change once the Company's EIM benefits model is updated with new Quarter 4 2019 data in the Company's March Forecast filing. This estimate may also be updated in line with any change to Valmy Unit 1 OHAG costs.

Staff also notes that although potential benefits arising from Boardman being dispatched after its forecasted closure date are not foreseeable, and therefore not included in this estimate, any benefits would impact customers positively as a reduction to NPSE.

ISSUE 1. ENERGY IMBALANCE MARKET (EIM) BENEFITS

Q. Please provide an overview of your testimony regarding EIM benefits.

A. Staff's testimony is structured as follows:

- Overview of how the EIM functions, how utilities participate in the market, which utilities are participating in the market, and overall results in terms of benefits to participants.
- Description of EIM benefits forecasting model proposed by the Company for the test year, contrasted with previously used forecasting models.
- Discussion of Staff's concerns regarding the proposed model.
- Presentation of three proposed adjustments to the model, which Staff believes improve the accuracy of the calculation without delaying progress in the case.
- Recommendation for an EIM benefit totaling $20.7 million.

Q. Please explain how the EIM functions.

A. Electric generation and load must be instantaneously balanced for the electric grid to remain stable, as a large sustained imbalance between generation and load will cause both voltage and frequency instability on the grid. The balancing and coordination of generation assets is performed on several time scales, beginning months or weeks ahead with generation unit planning, on a day-ahead basis, and finally through real-time balancing, which is the realm of the EIM.

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 EIM market's automated economic dispatch system looks across multiple BAs to create a "merit order" of generation bids, prioritizing the lowest cost generation. The market dispatches the lowest cost generator to meet imbalances. It also optimizes the Company's base schedule when savings are available. This process is repeated in each five-minute period.

Q. Please provide more detail on how generators bid in the EIM market.

A. Along with communicating their base schedule, 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. This is communicated through a set of four decremental bids and ten incremental bids.

Figure 3 - Example of MW and Price tiers submitted to EIM

Decremental Tiers					Incremental Tiers		
	(max T4)	T2	T1	Base Schedule	T1	T2	(max T10)
MW	100	50	50	500MW	50	50	100
Tier $	($10)	($2)	$5		$20	$30	$80

Figure 3 demonstrates how a generator with a base schedule of 500MW could bid to reduce its generation by 50MW if the market price reaches $5, and increase its generation by 50MW if the market price reaches $20.

Q. Who participates in the EIM?

A. The EIM footprint includes portions of Arizona, California, Idaho, Nevada, Oregon, Utah, Washington, Wyoming, and one Canadian province.

The EIM was established by CAISO in November 2014, with PacifiCorp as the first external participant. NV Energy joined the market in late 2015, followed by Puget Sound Energy and Arizona Public Service in late 2016. Portland General Electric then joined the market in in late 2017, with IDP and Powerex beginning to participate in April 2018. Finally part of the Balancing Authority of Northern California joined in April 2019.

New entrants in 2020 and 2021 will expand the market's footprint further. They include Salt River Project in Arizona, Seattle City Light, Los Angeles Department of Water and Power, Public Service Company of New Mexico, Turlock Irrigation District in California, the remaining members of the Balancing Authority of Northern California, and NorthWestern Energy which serves customers in Montana, South Dakota and Nebraska.[8]

Q. What other benefits, in addition to balancing and optimized dispatch, does EIM participation provide to utilities?

A. Benefits to participating in the western EIM 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, reduced operational risk due to enhanced system reliability, and ability to better support the integration of renewable resources.[9]

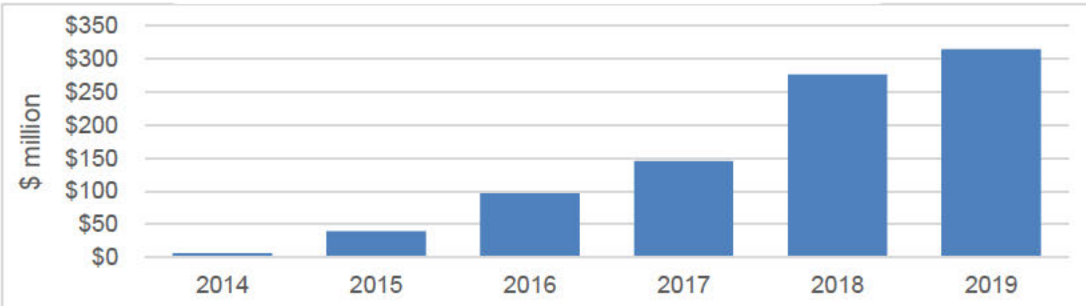
Q. Has Staff observed a trend in EIM benefits over time?

A. Yes. The EIM has been expanding rapidly to include more Balancing Areas (BA), and in line with the growth in the market's footprint, the EIM benefits of each participant has increased. The market now has nine participants,

8 See: www.westerneim.com/Pages/About/default.aspx.
9 Idaho Power Company, CASE NO. IPC-E-16-19 with Idaho Public Utilities Commission. See: puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE1619/CaseFiles/20160819Application.pdf.

compared with six participants when Idaho Power joined in 2018. An additional six participants are due to join EIM during 2020 and 2021.[10] Figure 4 below illustrates the increasing overall EIM benefits since the market's launch in 2014.

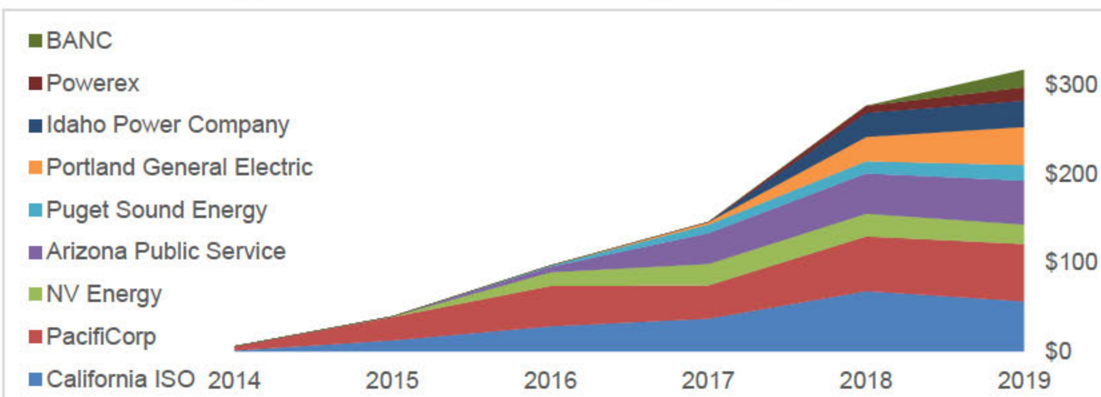
Figure 4 - Total EIM Benefits (all participants)



[11]

It is not simply that the overall benefits of the EIM are increasing as the market adds more participants, but benefits accruing to each participant have also continued to increase each year, as demonstrated by Figure 5

Figure 5 - Total EIM Benefit by Participant



[12]

10 See: www.westerneim.com/Pages/About/default.aspx.
11 Total benefit in 2019 is estimated, pending publication of EIM benefits report for Quarter 4 2019.
12 Total benefit in 2019 is estimated, pending publication of EIM benefits report for Quarter 4 2019.

Q. How are EIM benefits reflected in rates?

A. Idaho Power's power cost model, AURORA, does not consider EIM operations in its estimate of power costs. Consequently, the utility has proposed a methodology to estimate its EIM benefits outside of the AURORA model.

The Company's forecasted EIM benefit acts as an offset to power costs, and reduces the rates paid by customers.

Q. What EIM benefit has Idaho Power forecasted for the 2020 test year?

A. Idaho Power has forecasted a benefit of $15.6 million for the 2020 test year.

Q. How did the Company forecast this value?

A. The Company's model is loosely based on the CAISO's calculation of EIM benefits.[13] The CAISO estimates EIM benefits as the difference between the Company's costs and revenues participating in EIM, and what the Company's costs and revenues would have been absent EIM (the counterfactual dispatch).

In estimating the counterfactual dispatch, the EIM assumes the generation bids submitted reflect the Company's true cost of generation. With hydro generation however, power can be stored and moved into adjacent hours, and as a result the value of generation is not clear-cut.

The Company's proposed model makes some adjustments to the CAISO input data, intending to better reflect the value of hydro generation. It makes a total of three adjustments:

---

[13] See: www.westerneim.com/Documents/EIM_BenefitMethodology.pdf.

1. "*Zero-cost Hydro Adjustment*"[14] in which hydro generation bids in EIM are replaced with $0 bid, resulting in a forecasted EIM benefit of $19.06 million.
2. "*Hydro Net Export/Import Adjustment*" that estimates the benefit the Company may have received from net daily exports and imports in the absence of EIM. This adjustment sets hydro generation bid prices to equal the Company's daily average bilateral sales price. This results in a $2.2 million reduction to EIM benefits.
3. "*BPA Load Share Adjustment*" reduces the EIM benefit amount to reflect third party load, which represents 7.18 percent of load in the BA. This results in a $1.21 million reduction to EIM benefits.

Q. What approaches did Idaho Power take to estimating EIM benefits in previous years?

A. The Company began participation in the EIM in April 2018, so EIM benefits have been included in its APCU filings for the past two years only.

2018 APCU.

The Company initially proposed an EIM benefits forecast to equal EIM costs of $2.1 million in its October Update (equal to EIM costs).[15] Staff proposed an EIM benefits of $5.5 million in opening testimony, which was ultimately agreed upon by all parties in settlement.[16] This value was based on a study by Energy + Environmental Economics, Inc. commissioned by Idaho

14 Staff has followed the Company's naming of each step per Idaho Power/106, Blackwell/1.
15 UE 333, Idaho Power/106, Blackwell 1.
16 UE 333, Order No. 18-170, page 6.

Power, as well as an additional $1 million in benefits in accordance with Staff's estimate of flexible reserve benefits that were not included in the study.

2019 APCU.

The Company initially proposed a forecast of $4.5 million in EIM benefits in its October Update and March Forecast filings. The Company indicated that it was in the process of developing a methodology to forecast its EIM benefits.

The company filed supplemental March Forecast testimony in April 2019, including its model for forecasting EIM benefits. Similar to the model under review in the currently filing, the model proposed in the 2019 APCU included a zero-cost bid adjustment, and an adjustment for third party load in the Balancing Area Authority. Contrary to the EIM benefits model proposed in this filing, the proposed model did not include a “Hydro Net Export/Import Adjustment”. The proposed model did include an additional adjustment to reduce forecasted Green House Gas (GHG) benefits,[17] reflecting a change in the CAISO’s procedures related to the way GHG payments were awarded from November 2018 on.

The Company’s proposed model forecasted an EIM benefit of $11.93 million, and this was revised to $15.12 million once the model was updated with data from Quarter 1, 2019. Although Staff and CUB found this level of EIM benefit to be reasonable, both parties disagreed with the methodology utilized; particularly the Company's assumptions regarding the value of displacing hydropower dispatch.

---

[17] UE 350, Idaho Power/300, Annis/12.

Q. Please provide an overview of Staff's analysis of EIM benefits.

A. Staff issued 30 data requests relating to the EIM, and participated in two workshops with the Company.

The workshops provided an opportunity for Staff and the Company's to discuss issues including the Company's EIM operations, scheduling and trading of hydro generation, proposed EIM benefit forecasting methodology, and hydro management (including reservoir level targets and daily flow targets) in detail.

Staff analyzed each adjustment of the Company's EIM benefit calculation, along with the original calculation carried out by CAISO. This involved an immense amount of data, covering each five minute interval in the year, for each of the Company's 19 generator units operating in EIM. Five-minute data reviewed and analyzed by Staff includes bid prices and quantities, base schedules, dispatches and counterfactual dispatches, dispatch costs, transfers and transfer revenue, market prices, and GHG revenue and costs.

Q. Does Staff have concerns with the EIM benefits model proposed in this filing?

A. Yes. Staff has concerns with the model, specifically the "Zero-cost Hydro Adjustment". Staff does not agree that the model provides an optimal forecast of the Company's EIM benefits, and has ongoing concerns with the use of a zero hydro bid value.

Q. Please explain Staff's concerns with using a zero hydro bid value.

A. Staff's concerns with the use of a zero hydro bid value are as follows:

Value of hydro generation timing.

Hydro generation, particularly when paired with storage,[18] is a very flexible resource. This flexibility allows traders the opportunity to over-generate hydro power at peak price times, and purchase replacement power at low price periods. Setting hydro bids to $0 for every period does not account for the value of timing hydro generation.

Opportunity cost of hydro generation.

The Company's proposed model sets all bids for hydro units to zero when calculating its counterfactual dispatch. Although hydro has a zero generation cost, it is a limited resource, and has an opportunity cost. The Company's approach does not account for the opportunity cost of hydro generation.

The opportunity cost of hydro generation can be implied by the price at which the Company offsets other generation with hydro generation, or the price at which the Company purchases power, offsetting hydro generation. Staff has observed both of these values in the datasets provided by the Company, and has provided an example of the prices at which the Company purchased in EIM in Confidential Figure 6. **[BEGIN CONFIDENTIAL]**

Figure 6 - Idaho Power's monthly weighted average EIM purchase prices

[redacted]

[18] Idaho Power has storage capacity at nine of its 12 EIM participating hydro generator units.

[END CONFIDENTIAL]

No economic adjustment for hydro generation dispatch.

EIM benefits arise when a low cost generator is dispatched to meet imbalances, and when a utility's base schedule is optimized by dispatching units up or down from the base schedule.

In the Company's model, the dispatching up or down of hydro generation has a zero value, even when replacing a coal or natural gas fired generator in the utility's BA. Staff is concerned by the absence of an economic cost for hydro generation distorting the results of the forecast.

Q. What is Staff's proposal, considering the concerns that have been raised with the proposed model?

A. Staff does not agree that the methodology used by the Company to calculate the forecasted EIM benefit is reasonable. For this reason, Staff may propose alternatives or adjustments to the methodology used in this case in future proceedings.

Nevertheless, for the purpose of determining a forecasted EIM benefit for the current case in an expedient manner, Staff has proposed to use a modified version of the Company's model.

Q. What modifications have Staff proposed for the Company's model?

A. Staff has proposed three adjustments to the methodology proposed by the Company:

1. Use of hourly mid-market Mid-C prices in lieu of the daily average bilateral sales price for the Company's "Hydro Net Export/Import Adjustment". Combined with Staff's second proposed adjustment, this results in a $0.1 million reduction in EIM benefits.
2. Use of hourly data for the Company's "Hydro Net Export/Import Adjustment". Combined with Staff's first proposed adjustment, this results in a $0.1 million reduction in EIM benefits.
3. Use of growth factor in forecasted EIM benefits, reflecting the consistent annual growth in benefits experienced by all EIM participants. This results in a $5.1 million increase in EIM benefits.

Staff notes that although the first and second proposed adjustments to the "Hydro Net Export/Import Adjustment" reduce EIM benefits to customers, they provide a more accurate forecast for the APCU.

Q. Please explain Staff's first recommendation, which is to use Hourly Mid-Market Mid-C Prices for the Company's "Hydro Net Export/Import Adjustment".

A. Staff notes that that there are limitations to the Company's proposal to use its average daily bilateral price as a proxy for the counterfactual trading operations absent an EIM market opportunities. Staff believes that these limitations can be addressed by using the mid-market Mid-C price for the following reasons:

1. Mid-C data is available for almost all hours and days, **[BEGIN CONFIDENTIAL]** [redacted] [END CONFIDENTIAL]

4. Mid-C index is a transparent and trusted price in the region.

Staff's recommendation on this matter, combined with Staff's second proposed modification, results in a $0.1 million reduction in EIM benefits.

Q. Please explain Staff's second recommendation, which is to use hourly data for the Company's "Hydro Net Export/Import Adjustment".

A. Staff notes that the use of a net daily export/import value does not account for the potential benefits that would have been achieved by the Company if trading

[19] [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

at hourly prices outside EIM. This is because the volatility of within-day power prices affects the value of power which is sold or purchased, and may present power price arbitrage opportunities.[22] Staff has illustrated this using an example from the Company's EIM benefits model in Confidential Figure 7 below. **[BEGIN CONFIDENTIAL]**

Figure 7 - Example of Trading at Hourly Intervals

[redacted]

[redacted]

[22] Note that power price arbitrage opportunities are a particular advantage of hydro generation. This is because to the extent that water can be stored by the trader, the trader can move surplus generation from a low priced hour to a high-price hour.

[redacted] **[END CONFIDENTIAL]**

Staff's recommendation on this matter, combined with Staff's first proposed modification, results in a $0.1 million reduction in EIM benefits.

Q. Please explain Staff's recommendation to use an annual growth factor in forecasting EIM benefits.

A. As detailed on pages 10 and 11, there has been consistent year-on-year growth in the benefits accruing to EIM participants since the market's inception.

Despite this fact, the EIM benefits forecasting model proposed by the Company is back-ward looking, and makes no adjustment for growth in EIM benefits.

Staff's has calculated that the average growth rate in EIM benefits to participant has ranged from 22 percent to 42 percent[23] over the past three years. This growth is summarized in Figure 8.

Figure 8 - Growth in EIM benefits 2017 - 2019

Year ending	Average growth
Q3 2016 - Q3 2017	32%
Q3 2017 - Q3 2018	42%
Q3 2018 - Q3 2019	22%

Staff finds that it is incorrect to exclude growth from the EIM benefits forecast considering this stellar growth record. Staff recommends an adjustment for annual growth of 22 percent to the modelled EIM benefit value.

[23] Quarterly EIM benefits reports for Quarter 4 2016 through Quarter 3 2019. See: www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

Staff recommendation to use a 22 percent growth factor will make the EIM benefit forecast more forward-looking. Furthermore, it is both a conservative estimate of growth, and the most recent measure of annual growth available.

Accounting for the test year which begins on April 2020, and the most recent EIM benefits data for the period ending September 2019, Staff's recommendation on this matter results in an increase in EIM benefits of $5.1 million.

Q. Is Staff monitoring any other aspects of EIM?

A. Yes, Staff is monitoring the costs involved in EIM participation, and the issue of wheeling revenues in the EIM.

Q. Please detail Staff's observations regarding EIM O&M.

A. Staff monitors EIM participation costs to ensure their reasonableness, and to ensure that the benefits of participating in this optional market exceed the costs.

The October Update proposes an 18 percent increase in the Company's EIM O&M costs for the 2020 test year.[24] Upon querying this with the Company, Staff learned that the main driver of this change is that only seven months' of O&M costs were included in the prior APCU, with the initial five months' of costs being deferred as authorized in Docket No. UM 1821(1). Other drivers of this change include the addition of a full-time employee dedicated to EIM activities and an increase in software expenses related to the Company's GHG

[24] UE 350, Idaho Power/106, Blackwell/1; UE 366, Idaho Power/107, Blackwell/1.

transaction management software and EIM benefits calculation shadowing software.

Staff notes that the Company's forecasted EIM benefit of $15.6 million in the 2020 test year is far in excess of its total system wide costs of $3.15 million.

Q. Please explain Staff's concerns regarding wheeling revenues in EIM.

A. Staff's concerns lay in the fact that EIM entities that facilitate wheeling power do not currently receive any benefit for doing so. Oregon's IOUs are in somewhat advantageous locations in relation to other EIM participants, and as the EIM footprint grows and the market continues to change, wheel-through transfers may become more common.[25]

Figure 9 - Map showing Idaho Power's physical location in EIM

Figure 10 shows the proportion of wheel-through MWh in proportion to net imports and net exports, for each EIM participant in Quarter 3 2019.

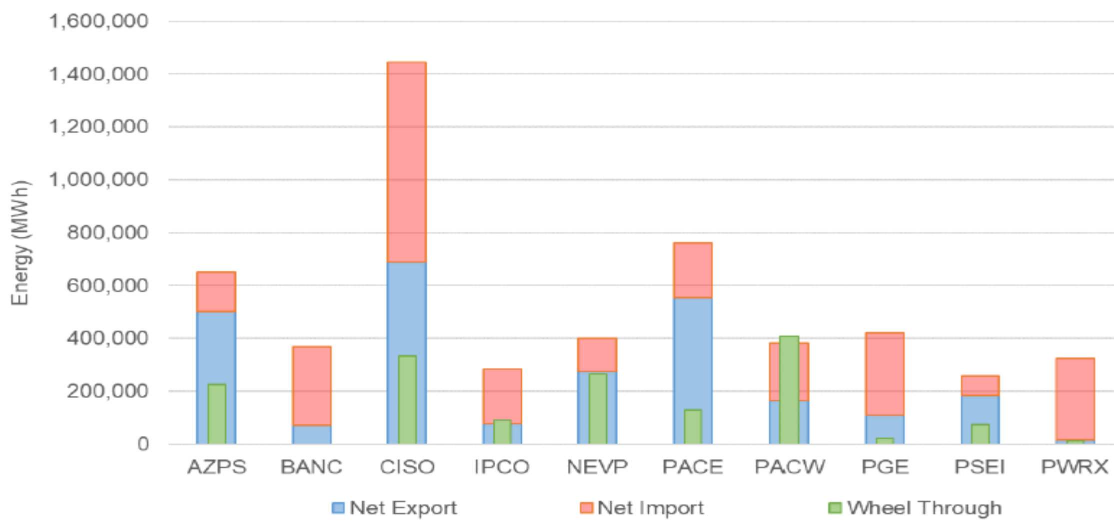
Staff notes that the CAISO has committed to monitoring EIM wheel-through volumes[26] to assess whether as the market grows, a market solution

[25] EIM benefits report Quarter 3 2019. See: www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

[26] CAISO's monitoring of wheel-through volumes is undertaken via the Western EIM Consolidated Initiatives stakeholder process.

may be needed to ensure that wheeling benefits are shared equitably between the sink, source and facilitating EIM participants.

Figure 10 - CAISO estimated wheel through transfers in Q3 2019 [27]



Q. Please summarize Staff's position on EIM benefits.

A. Staff continues to have concerns over the methodology. Nevertheless, for the purpose of determining a forecasted EIM benefit for the current case in an expedient manner, Staff has proposed to use a modified version of the Company's model.

Staff's proposed modifications include using the Mid-C mid-market price and hourly data in the Company's "Hydro Net Export/Import Adjustment", and the inclusion of an annual growth factor of 22 percent.

The overall effect of Staff's proposal is a $5.0 million increase in EIM benefits.

[27] EIM benefits report for Quarter 3 2019. See: www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

ISSUE 2. NET POWER SUPPLY EXPENSES AND RATE SPREAD

Q. Provide a brief overview of how the Company calculates its Net Power Supply Expenses (NPSE).

A. The Company calculates NPSE by adding together the annual forecasted cost of each generation type (including PURPA), and subtracting power cost offsets, which for Idaho Power are forecasted sales revenue and EIM benefits.[28] The Total Net Power Supply Expense is divided by the MWh forecasted customer sales in the year, to derive a per MWh unit cost.

Q. Has Staff reviewed the Company's NPSE calculations?

A. Yes. Staff reviewed the calculations carried out by the Company for accuracy, and to ensure consistency with previous years. Staff is satisfied that NPSE has been calculated in accordance with precedent.

Q. Please summarize the methodology used for rate spread.

A. As detailed in Staff witness Gibbens' testimony, APCU 2017 parties stipulated that in future APCU filings Idaho Power would use the "total cost method" to allocate power costs between the Company's jurisdictions, and among rate classes in Oregon.

This methodology was further refined in APCU 2018, when the Commission approved a stipulation including a clearly defined rate spread methodology with a glide path to protect against rate shock to any one schedule. Under this methodology the Oregon jurisdictional share of total NPSE, instead of the Oregon jurisdictional share of incremental NPSE, will be allocated to individual

---

[28] EIM benefits and surplus sales revenue benefit customers as an offset to power costs.

customer classes on the basis of normalized jurisdictional forecasted sales at the generation level for the forecast April through March test period. 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.[29]

Q. Does Staff have concerns with Idaho power's application of the Total Cost Method in the 2019 APCU?

A. No. Staff found no issues with the calculations. Idaho Power has correctly implemented the total cost method, which will ensure no over or under recovery of power costs. Furthermore, no single customer class has experienced a rate increase in excess of the agreed cap, so there was no shortfall to be reallocated among all other customer classes.

Q. Does this conclude your testimony?

A. Yes.

[29] UE 333, Order No. 18-170, page 5.

CASE: UE 366
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

February 4, 2020

WITNESS QUALIFICATIONS STATEMENT

NAME:	Moya Enright
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility and Energy Analyst Energy Rates, Finance and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Energy Risk Professional Certification (part-qualified). Global Association of Risk Professionals. M.Sc. Political Science, 2015. University of Amsterdam. M.Sc. Investment, Treasury and Banking, 2011. Dublin City University. B.A. International Business and Languages, 2008. Dublin City University through a joint curriculum with École Supérieure de Commerce de Montpellier.
EXPERIENCE:	Senior Utility and Energy Analyst at OPUC since January 2019. Energy Trader for Meridian Energy from 2015 to 2019. Meridian Energy is a power generator and retailer operating both in New Zealand and Australia. Trading and Operations Analyst at Tynagh Energy from 2011 to 2013. Tynagh Energy is an independent power producer operating in the Republic of Ireland. Senior Electricity Market Controller at EirGrid from 2008 to 2011. EirGrid is the Irish electricity Transmission System Operator. It operates the Single Electricity Market for the Republic of Ireland and Northern Ireland. Accounts Assistant roles from 2004 to 2008, including Audit Intern at KPMG in Northern Ireland.

CASE: UE 366
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

February 4, 2020

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

A. My name is Sabrinna Soldavini. I am a Senior Regulatory Analyst employed in the Energy Finance and Audit Division 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/201.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to represent Staff's position on the issues of AURORA re-pricing, Bridger Coal Company Depreciation, Boardman 2020 Operations, and Valmy Unused Capacity.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/202, Idaho Power Response to Staff Data Requests and Exhibit Staff/203, Idaho Power Confidential Response to Staff Data Requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. AURORA RE-PRICING

Q. Please explain the issue of AURORA Re-Pricing.

A. Per the settlement approved in Order No. 08-238, Idaho Power's Base Net Power Supply Expenses (NPSE) are calculated via a two-step process. The AURORA model is first used to determine the net power supply average dispatch cost for normal loads and average stream flow conditions. Then, the model determined wholesale electric prices for purchased power and surplus sales are replaced with an average forward electric price curve.

Idaho Power uses the AURORA model to forecast purchased power and surplus sales volumes for an April to March Test Period. The Company first utilizes the AURORA-modeled electricity prices to determine levels of purchased power and surplus sales volumes based on the concept of economic dispatch – optimizing the dispatch of electricity generation facilities to meet system load, at least cost. Pursuant to Order No. 08-238, these AURORA generated volumes are then re-priced using a forward electricity price curve for the Mid-Columbia (Mid-C) hub. Once re-priced and adjusted for inflation, these values become the final estimates for purchased power expense and surplus sales revenue in the Company's forecasted NPSE.

Q. What was the effect of re-pricing in the 2020 October update?

A. For the October 2020 update, the AURORA-generated forecast for purchased power expenses and surplus sales revenues are approximately $35.4 million and $24.7 million, respectively.[1] After re-pricing with Mid-C hub forward curves,

[1] Idaho Power/100, Blackwell/12 through Blackwell/13.

purchased power expenses increased by approximately $8.7 million, from $35.4 million to $44.1 million, while surplus sales revenues also increased by approximately $4.6 million, from $24.7 million to $29.3 million.[2] The net result of re-pricing, for the October update is an increase to NPSE of approximately $4.1 million.

Q. How has re-pricing AURORA typically adjusted the NPSE estimates for the October update?

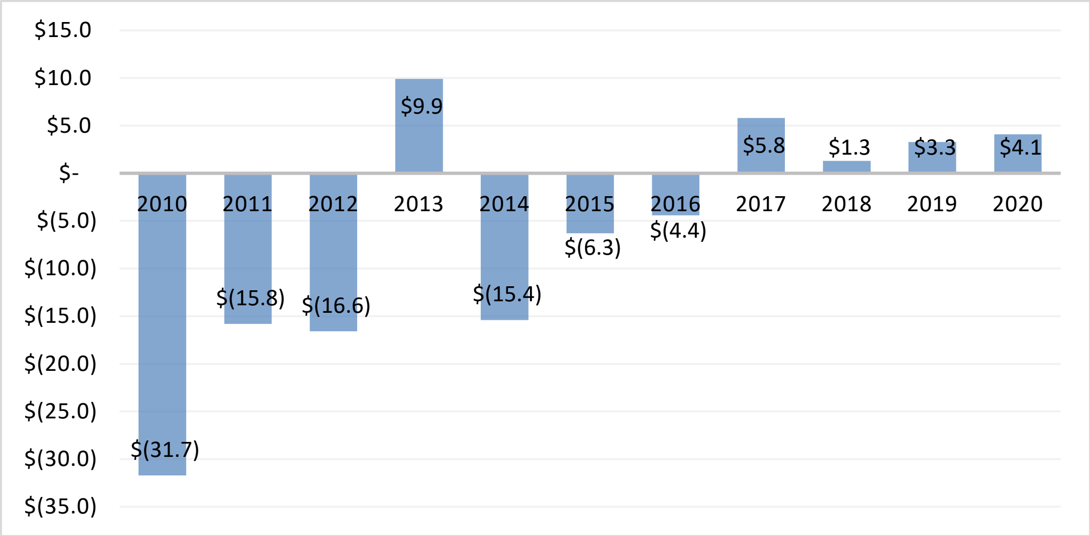
A. The results of re-pricing from 2010 to 2020 can be seen in the table and chart below.

Figure 1 Re-Pricing and the Effect to NPSE ($Millions of Dollars)

	Before Repricing		After Repricing		
Year	Purchased Power	Surplus Sales	Purchased Power	Surplus Sales	Effect on Total NPSE
2010[3]	$40.2	$84.5	$38.4	$114.4	-$31.7
2011[4]	$36.3	$61.3	$42.1	$82.9	-$15.8
2012[5]	$40.3	$86.9	$41.9	$105.1	-$16.6
2013[6]	$29.6	$110.3	$14.3	$85.1	$9.9
2014[7]	$20.6	$72.5	$19.7	$86.9	-$15.4
2015[8]	$15.0	$56.1	$14.2	$61.6	-$6.3
2016[9]	$8.3	$54.8	$10.2	$61.0	-$4.4
2017[10]	$16.0	$49.1	$14.9	$42.2	$5.8
2018[11]	$15.7	$31.3	$12.1	$26.4	$1.3
2019[12]	$13.4	$36.1	$11.0	$30.4	$3.3
2020[13]	$35.4	$24.7	$44.1	$29.3	$4.1

[2] *Ibid.*
[3] UE 214, Idaho Power/100, Wright/7.
[4] UE 222, Idaho Power/100, Wright/6.
[5] UE 242, Idaho Power/100, Wright/6.
[6] UE 257, Idaho Power/100, Wright/8.
[7] UE 279, Idaho Power/100, Wright/8.
[8] UE 293, Idaho Power/100, Wright/7.
[9] UE 301, Idaho Power/100, Noe/13.
[10] UE 314, Idaho Power/100, Blackwell/13.
[11] UE 333, Idaho Power/100, Blackwell /12.
[12] UE 350, Idaho Power/100, Blackwell/13.
[13] Idaho Power/100, Blackwell/13.

Figure 2 Re-Pricing and the Effect to NPSE ($ Millions of Dollars)



Observable in the data is a general shift in both the direction and absolute magnitude of the effect of re-pricing the AURORA modeled volumes. From 2010 to 2016, re-pricing produced benefits to Oregon ratepayers in the form of reduced NPSE. For the last four years, re-pricing has led to increases in total NPSE. As noted, the absolute magnitude of the re-pricing effect has generally been decreasing since 2010, from a $31.7 million dollar effect to NPSE in the 2010 October update to a $4.1 million dollar effect to NPSE in the 2020 October update.

Q. Does Staff have a recommendation for this issue?

A. Staff does not propose a change with regards to re-pricing at this time. As the absolute magnitude of re-pricing's effect on NPSE has generally been decreasing over time, Staff feels the difference between the AURORA generated NPSE for purchased power and surplus sales volumes remains reasonable when compared with the re-priced NPSE. Staff does note however, that in a general rate case, it may consider an in depth, long-term review of the differences between AURORA generated prices and the Mid-C adjusted prices.

ISSUE 2. BRIDGER COAL COMPANY DEPRECIATION

Q. Please explain Bridger Coal Company's (BCC) relationship to Idaho Power.

A. BCC is a joint venture of Idaho Power and PacifiCorp, which is owned by Idaho Energy Resources Co. (IERCO), a wholly owned subsidiary of Idaho Power, and a separate subsidiary of PacifiCorp. Pursuant to Commission order, "separate record and accounts for IERCO are maintained and the operations of IERCO are summarized in Idaho's semiannual reports of operations filed with the Commission. IERCO's results of operations have been merged, consolidated, and included with Idaho's for the purposes of filing of income tax returns and for the rate-making process."[14]

Q. Please summarize the history of BCC depreciation as it relates to Idaho Power's APCU?

A. In the 2018 APCU Staff raised the issue of the Company's recovery of depreciation expense from ratepayers (through the cost of fuel) related to plant that has been added since the Company's last general rate case, and has yet to be undergo a prudence review, as well as the depreciation rate of some BCC assets.[15] In the 2018 stipulation approved in Order No. 18-170, the stipulating parties agreed that in subsequent APCUs, Idaho Power would submit workpapers detailing the justification of the depreciable lives of BCC

[14] Order No. 91-567.
[15] UE Staff/200, Kaufman/5 through Kaufman/9.

assets as well as any variations to BCC depreciation levels from those established in the Company's most recent rate case.

Subsequently, in the 2019 stipulation approved in Order No. 19-189, Idaho Power agreed to hold a workshop with PacifiCorp to further discuss the issue of BCC depreciation expense included in the APCU with Staff and the Oregon Citizens' Utility Board (CUB).

Q. Has Staff confirmed Idaho Power provided the necessary workpapers, as outlined in Order No. 18-170?

A. Yes. Idaho Power has submitted the required workpapers outlining the depreciable lives of BCC assets. The associated workpapers also include a description of how and why BCC depreciation has varied from the level set in its most recent general rate case.

Q. How has BCC depreciation expense varied since the Company's most recent rate case?

A. Since the Company's last general rate case, BCC depreciation expense has ranged from approximately **[Begin Confidential]** [redacted] **[End Confidential]**. Idaho power calculates BCC depreciation expense for the period ranging from April 2018-March 2019 at approximately **[Begin Confidential]** [redacted] **[End Confidential]**.This represents an approximately **[Begin Confidential]** [redacted] **[End Confidential]** over the prior year, which the Company notes is largely due to **[Begin Confidential]** [redacted]

[redacted] **[End Confidential]**.

Q. Can Staff confirm that Idaho Power held a workshop to address BCC depreciation expense included in the APCU as required by Order No. 19-189?

A. Yes. Pursuant to Order No. 19-189, Idaho Power and PacifiCorp held a workshop on September 23, 2019 to discuss BCC depreciation expense and its inclusion in the APCU. Staff has provided a copy of the presentation in Staff Exhibit 203.[16]

Q. Does Staff have a recommendation for this issue?

A. No. Staff has no further recommendations for BCC depreciation as it relates to the APCU at this time.

[16] Exhibit Staff/203, Soldavini/1 through Soldavini/13.

ISSUE 3. BOARDMAN OPERATIONS 2020

Q. Please provide background for this issue.

A. Idaho Power is a joint owner of the Boardman plant, and owns 10 percent of the plant, while Portland General Electric (PGE) owns the remaining 90 percent. Idaho Power and PGE are set to cease operations at the Boardman plant by December 31, 2020. To address the winding down of operations and expected supplies and inventories, AURORA has been updated accordingly, and Idaho Power has included an adjustment to AURORA that sets October 31, 2020, as the last day of operations at Boardman leading to a 100 percent deration of the plant for November and December 2020.[17]

Q. Why has Idaho Power chosen to model October as the last month of operations in AURORA?

A. When the Boardman plant is shut down at the end of 2020, any coal remaining on the ground must ultimately be disposed of at a material cost. In order to strategically manage coal inventory, and minimize the amount of coal left on the ground after December 31, 2020, AURORA has been updated to show a 100 percent deration for Boardman after October 2020. Thereby ensuring AURORA cannot dispatch Boardman in subsequent months.

Essentially, Idaho Power has modeled 2020 Boardman operations to mirror the methodology approved in PGE's 2020 Automatic Update Tariff (AUT). In Docket No. UE 359, PGE's 2020 AUT, the stipulation approved in Order No. 19-329 permitted PGE's modeling the last day of planned operations

[17] Exhibit Staff/202, Soldavini/1.

at Boardman to be October 31, 2020, with a 100 percent maintenance deration in November and December of 2020 to minimize the amount of coal left on the ground. For coal left on the ground after December 31, 2020, a coal removal cost estimated at $37.50 per ton will apply and be charged to customers as decommissioning costs through PGE's Schedule 145, Boardman Power Plant Decommissioning Adjustment. Given the coal disposal cost, it is likely cost effective to manage coal inventories and stop coal deliveries earlier than December 2020, minimizing the amount of coal left on the ground. Limiting coal deliveries to Boardman in 2020 allows for the burning of coal that will have already been purchased and delivered earlier in the year, with the intent of minimizing coal disposal costs.

As PGE owns 90 percent of the Boardman plant, and Idaho Power owns 10 percent, Staff finds it reasonable that Idaho Power would propose to model the last day of Boardman operations consistent with PGE's approved modeling, and takes no issue with Idaho Power's choice of modeling assumption.

Q. What is the effect of this modeling assumption?

A. In response to a Staff data request, Idaho Power notes that the effect of modeling a 100 percent maintenance deration for November and December 2020 is a decrease to NPSE of approximately $580,000 or $27,000 on an Oregon allocated basis.[18]

Q. Why does removing Boardman from operations in November and December decrease NPSE?

[18] Exhibit Staff/202, Soldavini/2.

A. Though seemingly counterintuitive that removing a thermal resource like Boardman would lower NPSE, Staff notes that because the version of AURORA Idaho Power uses for its APCU does not have perfect foresight,[19] it is conceivable that given minimum run times and other dispatch constraints, when Boardman was allowed to run in November and December of 2020, it was not actually the least cost resource.

Though AURORA would have committed Boardman to dispatch in an hour where it was economic to run given the market price, once it was committed, it was committed for at least its minimum run time (48 hours). As the model does not have perfect foresight, it would have committed Boardman without knowledge of future market prices. So even if Boardman became uneconomic to run in hours 28-35 for example, Boardman would still run for the entire 48 hours. The removal of Boardman from the resource mix in November and December of 2020 may have allowed a resource with lower ramp rates, minimum run times, etc. to dispatch instead, lowering the overall NPSE.

Q. Is it possible that Boardman will still run in November and December of 2020, even though it has been modeled to cease operations in October of 2020?

[19] A model with perfect foresight is one in which there is no uncertainty, and can therefore correctly predict future events. For example, a NPSE model with perfect foresight would know with certainty the market price for each future hour, and would use the knowledge of those future prices before deciding to commit a resource. In the version of AURORA that Idaho Power uses, the model does not have perfect foresight, and decides to commit a unit based on the price in any given hour. Once committed, that unit is then committed for its minimum run time, regardless of whether the price drops after the hour it was committed, and the resource becomes uneconomic to run.

A. Yes. Although the Company has modeled a 100 percent deration for Boardman in November and December, in reality, if coal remains on site after October 2020, the decision to dispatch Boardman will be based on economics, i.e., the plant will run in November and December if it is economic to do so. Idaho Power is assuming the same $37.50 per ton coal removal cost for any coal remaining on the ground that PGE assumed in its analysis.[20] Essentially, if the cost to dispatch is less than the coal removal cost, Boardman will be operating in November and December of 2020.

Q. How does Idaho Power propose to account for any benefits if it determines Boardman is economic to run in November or December of 2020?

A. In response to Staff Data Request 49, the Company states that it does not intend to account for any potential customer benefits if Boardman is economic to run after the modeled shut down date of October 31, 2020, and states that it plans to accounts for these benefits only through the PCAM. [21] Staff believes this is insufficient. The choice to derate for November and December is merely a modeling choice to minimize the coal left on the ground, and subsequent coal removal charges; however, it is likely that Boardman will in fact dispatch in November and December of 2020. As such, Staff believes that any benefits on Boardman dispatch in November and December of 2020 should be returned to customers.

[20] Exhibit Staff/202, Soldavini/1, Idaho Power response to Staff DR No. 48.
[21] Exhibit Staff/202, Soldavini/3.

Q. What is Staff's recommendation for this issue?

A. Staff recommends that Idaho Power account for any benefits of economic dispatch of Boardman in November through December 2020 in a similar manner as PGE proposed to in UE 359. Staff recommends that Idaho Power track any benefits as the difference between settled Mid-C and Boardman dispatch costs (including fuel costs), with any realized value being included as an offset to NPSE in the 2022 APCU, the first APCU following the scheduled closure of Boardman.

ISSUE 4. VALMY UNUSED CAPCITY

Q. Please summarize the issue of Valmy unused capacity.

A. To account for revenues received from (or expenses paid to) NV Energy for usage of Idaho Power's unused capacity (or the usage of NV Energy's unused capacity), the 2017 APCU stipulation approved in Order No. 17-165 requires Idaho Power to include the three-year historical average of actual net balances associated with ownership partner use of Valmy as an offset to NPSE.

Q. What is the level of Valmy unused capacity in the 2020 October update?

A. For the 2020 October Update, the 2016-2018 historical average of net revenue paid to Idaho Power, associated with NV Energy's dispatch of Idaho Power's unused capacity at Valmy is $67,378 on a total system basis.

Q. Has Staff confirmed the Company has calculated the revenue from unused Valmy capacity using the stipulated methodology?

A. Yes, Staff reviewed the Company's calculation, including the Company's response to a Staff Data Request for the transactional level detail, and confirms that it has applied the stipulated methodology, the three year average of actual net balances, to calculate this component of the APCU.

Q. Does Staff have an adjustment for this issue?

A. Staff does not currently have an adjustment for this issue, but notes that Staff witness Scott Gibbens has an outstanding issue related to the Valmy OHAG forecast, which may warrant an adjustment to the net balances associated with partner use of Valmy.[22] Staff reserves the right to make an adjustment based on the outcome of this outstanding issue later in this proceeding.

Q. Does this conclude your testimony?

A. Yes.

[22] Exhibit Staff/300, Gibbens/6.

CASE: UE 366
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

February 4, 2020

WITNESS QUALIFICATION STATEMENT

NAME: Sabrinna Soldavini

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Regulatory Analyst
Energy Rates, Finance and Audit Division

ADDRESS: 201 High St. SE Ste.
100 Salem, OR
97301-3612

EDUCATION: Masters of Science, Agricultural Economics
Purdue University, West Lafayette, Indiana

Bachelor of Science, Economics
University of Oregon, Eugene, Oregon

EXPERIENCE: I have been employed by the Oregon Public Utility Commission (Commission) since August 2018 in the Energy, Rates and Finance Division. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues for filings made by utilities.

Prior to working for the Commission I was a consulting analyst for MGT Consulting, primarily to help large public school districts prepare for bond proposals through budget analysis and statistical modelling/projections of student and demographic data. Prior to this work, I was a Research Assistant at Purdue University where I conducted research on the economic feasibility of biofuel feedstocks. Additionally, I have experience working in Data Analysis, and Program Coordination within the technology sector.

CASE: UE 366
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

February 4, 2020

UE 366 – 2020 APCU – Response to Staff's DRs 45-49

TOPIC OR KEYWORD: BOARDMAN SHUTDOWN

STAFF'S DATA REQUEST NO. 48:

Please refer to Idaho Power/100, Blackwell/6.

a. Please provide, in excel format, the Company's Boardman shutdown model. Please include all assumptions and calculations used in AURORA to model October 2020 as the last month of planned operations.
b. Please list any supply constraints currently affecting Boardman operations in 2020.
c. What is the cost impact of modeling a 100% maintenance deration for the period between November 1 and December 31, 2020, as compared to operating through the entirety of 2020?
d. Please provide, in excel format, the Company's estimated coal removal cost per ton. Please show how the Company derived this value, including the source of any assumptions.

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

a. To model October 2020 as the last month of operations at Boardman within the AURORA model, the Company input an end of operations date for the plant of October 31, 2020. This input within the AURORA model prohibits the dispatch of Boardman beyond this date. Because these calculations occur within AURORA there is no Excel-based file.

b. Idaho Power is not expecting any supply constraints for fuel or emission control materials for Boardman in 2020.

c. The total AURORA-modeled NPSE (before re-pricing and the addition of PURPA expense) associated with modeling October 2020 as the last month of operations at Boardman is $164,822,511, as shown on Idaho Power/101, Blackwell/1. The total AURORA-modeled net power supply expense ("NPSE") (before re-pricing and the addition of PURPA expense) associated with modeling December 2020 as the last month of operations at Boardman is $165,435,688. Therefore, modeling October 2020 as the last month of operation as compared to December 2020 results in a reduction in AURORA-modeled NPSE (before re-pricing and the addition of PURPA expense) of $613,177 or $28,398 on an Oregon allocated basis.

d. Idaho Power and Portland General Electric ("PGE") are carefully coordinating coal deliveries and managing inventories to minimize the risk of any coal remaining unburned at the end of 2020. There is coal at the base of the existing coal pile that will need to be recovered (separated from the dirt). The partners are planning on bringing a contractor on-site in 2020 to start the recovery process of the coal, which, in turn, will be burned in the boiler. Any coal that cannot be recovered will be transported and disposed of at a landfill. Considering data from PGE's on-site biomass disposal efforts, Idaho Power estimates that the disposal of any unrecoverable coal would cost approximately $37.50/ton.

UE 366 – 2020 APCU – Supplemental Response to Staff's DRs 45-49

TOPIC OR KEYWORD: BOARDMAN SHUTDOWN

STAFF'S DATA REQUEST NO. 48:

Please refer to Idaho Power/100, Blackwell/6.

a. **Please provide, in excel format, the Company's Boardman shutdown model. Please include all assumptions and calculations used in AURORA to model October 2020 as the last month of planned operations.**
b. **Please list any supply constraints currently affecting Boardman operations in 2020.**
c. **What is the cost impact of modeling a 100% maintenance deration for the period between November 1 and December 31, 2020, as compared to operating through the entirety of 2020?**
d. **Please provide, in excel format, the Company's estimated coal removal cost per ton. Please show how the Company derived this value, including the source of any assumptions.**

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

Idaho Power provides the following supplemental response to part c in response to Staff's Data Request No. 75.

c. Idaho Power's 2020 APCU filing reflects the modeling of a 100% deration for the Boardman plant for November 1, 2020, through December 31, 2020, within AURORA. As discussed in the response to Staff's Data Request No. 73, the Company has since made an update to Confidential Workpaper Attachment 9 regarding the 2020 coal price for Boardman. Using this updated coal price, total AURORA-modeled NPSE (before re-pricing and the addition of PURPA expense) associated with modeling October 2020 as the last month of operations at Boardman is $164,855,472. The total AURORA-modeled NPSE (before re-pricing and the addition of PURPA expense) associated with modeling December 2020 as the last month of operations at Boardman is $165,435,688. Therefore, modeling October 2020 as the last month of operation as compared to December 2020 results in a reduction in AURORA-modeled NPSE (before re-pricing and the addition of PURPA expense) of $580,216 or $26,871 on an Oregon allocated basis.

UE 366 – 2020 APCU – Response to Staff's DRs 45-49

TOPIC OR KEYWORD: BOARDMAN SHUTDOWN

STAFF'S DATA REQUEST NO. 49:

If the plant is economic to run, and there is coal left on the ground after October 2020, how does the Company plan to account for any realized benefits?

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 49:

If there is coal left on the ground after October 2020 and Boardman is economic to run, the plant will be dispatched and both the costs and benefits of dispatching the plant will be captured through the Company's Power Cost Adjustment Mechanism, which tracks and trues-up deviations in forecast NPSE included in the APCU and actual NPSE.

CASE: UE 366
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Opening Testimony

February 4, 2020

Staff Exhibit 203 is confidential

Subject to Protective Order No. 19-379

CASE: UE 366
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

February 4, 2020

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

A. My name is Scott Gibbens. I am a Senior Economist employed in the Energy, Finance, and Audit Division 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/301.

Q. What is the purpose of your testimony?

A. I discuss Staff's review of Idaho Power Company's compliance with previous Commission orders regarding allocation and "Oil, Handling, Administrative & General" (OHAG) expenses. I also discuss Staff's review of the load forecast, fuel prices and wholesale market transactions.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/302, Idaho Power's responses to Staff Data Request Nos. 59 and 60.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. ALLOCATION

Q. What is the history of this issue?

A. In UE 314, Staff found that the Company's previously approved cost allocation methodology could result in over/under collection of costs if the incremental net supply power expense (NPSE) was driven by unequal changes in load between states or rate classes. Previously, only the incremental change resulting from Idaho Power's annual APCU filings would be allocated in that particular year's filing. However, only allocating the incremental change did not account for the changes in recovery that might occur for the amounts previously in base rates. As a result, Staff recommended and the Commission adopted in Order No. 17-165, the "Total Cost" allocation method. This allocates total NPSE every year to ensure appropriate recovery of costs. The 2017 stipulation states, "Idaho Power will calculate the Oregon jurisdictional share of the APCU revenue requirement by multiplying the system NPSE total per-unit cost by the forecasted Oregon jurisdictional loss-adjusted normalized sales for the April through March test period."[1]

Q. Has Idaho Power accurately followed the total cost allocation method?

A. Yes, Staff's review of the Company's workpapers matches the Company's stated calculation in Idaho Power/100, Blackwell/23, line 14. Staff found no issues with the methodology or calculation.

[1] Order No. 17-165, Appendix A, Page 8, Line 9-12.

ISSUE 2. FUEL PRICES

Q. How does the coal price forecast for the 2020 APCU compare to the prior years' update?

A. Prices are based on historic coal price data and information gathered by Idaho Power and their operating partners for expected price changes during the test year. Overall, the prices are similar to the previous year, with slight decreases shown at Bridger and Boardman and a slight increase at Valmy.

Q. How have the updated coal prices changed the AURORA dispatch of coal?

A. Although the prices stayed relatively flat, lower priced market purchases and fewer economic sales opportunities have resulted in a projected 41 percent decrease in coal-based generation. This has resulted in a 37 percent decrease in coal expense. Because OHAG has remained relatively flat, this has resulted in a slight increase in the per unit cost of generation for coal. The exact amount is $38.90 per MWh, compared to $36.74 per MWh for the 2019 October Update. However, the difference is small and Staff has no issue with the reasonableness of the forecast due to the Company's compliance with the Commission approved OHAG forecasting methodology, which is discussed below.

Q. How does the natural gas price forecast for the 2020 APCU update compare to the prior year's update?

A. The Henry Hub price used for the October 2019 update was $3.13 per MMBtu, and $2.71 per MMBtu in 2020. This is a 13 percent decrease ($0.42).[2] However, the actual dispatch price of natural gas has increased for Idaho Power's natural gas units due to a 47 percent increase in the Sumas basis price. Meaning that although the price of natural gas in the main hub of the nation is expected to decrease, prices in the Northwest are expected to increase comparatively.

Q. How is the Henry Hub forecast developed?

A. The current APCU filing uses multiple natural gas forecast data points and uses an average price for determining a normalized price. The methodology was approved in Docket Nos. UE 314 and UE 333. The Company uses four separate forecasts from third parties to calculate the normalized prices, namely the NY mercantile Exchange, the Energy Information Administration, Moody's Analytics, and S&P Global Platts.

Q. Does Staff find any issue with the Henry Hub forecast?

A. No. Staff reviewed the Company's methodology and finds it in compliance with previously approved Commission direction. The use of the four indices provides a robust and reasonable forecast.

Q. Does Staff find any issue with the Sumas Basis forecast?

A. No. The Enbridge natural gas pipeline rupture that occurred in October 2018, has had a lasting effect on prices in the region. Staff has seen a shift in the Sumas basis for all electric utilities' power cost filings. Although gas

[2] Idaho Power/100, Blackwell/9.

continues to be cheaper in the region than at Henry Hub, the difference has shrunk in terms of actual prices and in forecasted prices. As such, Staff finds the increase reasonable and in line with other Company projections.

ISSUE 3. OIL, HANDLING, ADMINISTRATIVE, AND GENERAL

Q. What are Oil, Handling, Administrative, and General (OHAG) expenses and how are they included in Idaho Power's NPSE?

A. OHAG expenses include the costs of diesel burned at the plant for startup and flame stabilization; labor, equipment, materials, supplies and related overhead loadings on these costs to move coal from the train trestle (or in the case of Bridger, the conveyor) to the coal silos; and labor associated with coal fuel procurement and routine fuel analysis.[3] Actual OHAG expenses vary depending on overall production at each plant.

In Docket No. UE 301 the Commission adopted a revised methodology that separately accounted for OHAG costs associated with Idaho Power's dispatch of the coal plants and the proportional share of total OHAG costs Idaho Power is required to pay to its co-owners.[4] Under this 'Hybrid Model' Idaho Power would include only the portion of OHAG expenses associated with Idaho Power's dispatch in the AURORA model while separately accounting for Idaho Power's proportional share of OHAG expenses resulting from its partners' dispatch.

In Docket No. UE 314, the Commission adopted the parties' stipulation regarding Idaho Power's forecast of OHAG costs. Under the UE 314 stipulation, the forecast is based on a three-year historical average of actual

---

[3] UE 301 - Idaho Power/100, Blackwell/6.
[4] Order No. 16-206, App. A.

OHAG costs, with a growth (reduction) rate equal to the five-year historical average growth (reduction) rate.[5]

Q. Did Idaho Power calculate OHAG expenses consistently with the previously adopted methodology?

A. Yes, Staff reviewed the calculation to ensure the Company followed the methodologies set forth in the orders in Docket Nos. UE 314 and UE 301.

Q. Does Staff agree with Idaho Power's calculation of OHAG in the 2020 APCU?

A. Staff has two concerns regarding the use of the Hybrid Model when calculating the OHAG cost for the 2020 APCU. The first is the implication of the North Valmy Project Framework Agreement between NV Energy and Idaho Power, approved by the Commission in Order No. 19-341 on October 15, 2019. This agreement allows Idaho Power to cease operations at Valmy Unit 1, while its partner, NV Energy continues to operate the unit. The second, is the pending closure of Boardman at the end of the calendar year 2020.

Q. Why are these a concern with regard to OHAG?

A. The Hybrid Model is based on only historical usage and trends and on its surface does not take into account events which have recently or are expected to occur like the closure of a plant. In the case of Boardman, all operations are expected to stop, and thus variable O&M expenses for Boardman will cease as well prior to a full year of operation. In the case of Valmy, the Framework

---

[5] Order No. 17-165, p. 4.

Agreement specifies what O&M costs Idaho Power will continue to pay as NV Energy continues to operate Unit 1 of the plant.

Q. Did Idaho Power account for the closure of Boardman in the OHAG forecast?

A. Yes. Idaho Power calculated the forecasted monthly OHAG expense utilizing the hybrid model, but only included the OHAG monthly expense for the months (April – October) which Boardman is projected to generate power. The result is a reasonable forecast using the hybrid model, which accounts for the fact that the plant will only operate for a portion of the test year.

Q. Did Idaho Power account for the cessation of operations at Valmy unit 1 in the OHAG forecast?

A. No. After reviewing the treatment of OHAG in the Framework Agreement between Idaho Power and NV Energy, Staff concludes that there may be sufficient reason to alter the OHAG forecast for Valmy. The Company did produce the OHAG forecast using the Commission approved methodology; however this special event warrants an adjustment to the methodology for the plant until historic data is sufficient to forecast the expense.

Q. Does Staff have a recommendation for adjustment to the methodology?

A. Yes, Staff has a general concept for how the adjustment will work but has not determined the actual forecast at this time. Staff continues to work through the Framework Agreement to determine the exact manner in which Idaho Power will share in OHAG expenses with NV Energy. Staff endeavors to ascertain the percentage of OHAG costs Idaho Power will now pay compared to the amount it previously paid due to the new agreement. This percentage would then be used to discount the Hybrid Model forecast. For example, if Idaho Power is to pay approximately 50 percent of the Company's previous share of the OHAG costs for Unit 1, then a discount of 25 percent will be taken from the Hybrid Model forecast. In this example the Company now pays all of the Unit 2 costs it previously did and half of the Unit 1 OHAG costs. Staff will continue to work with the Company to identify the proper percentage and provide it in Reply Testimony.

ISSUE 4. WHOLESALE PURCHASES AND SALES

Q. Please describe the Company's projection for this year's market purchases and sales.

A. As mentioned previously, lower market prices have led to an increase in market purchases and a decrease in coal and natural gas generation in this year's APCU forecast. Compared to the previous October forecast, the amount of market and PPA purchases have increased by 60 percent, or four percent of the total generation mix. On the sales side, this year's forecast exhibits a 19 percent decrease compared to last year. Overall, the Company is still expected to be a net exporter into the market but only by about 0.2 million MWhs compared to last year's 1.2 million MWhs.

Q. Does Staff have concerns regarding the wholesale purchases and sales?

A. No. All of the relative changes between the generation mix follow a logical narrative. Lower market prices result in more market purchases and fewer opportunities for economic market sales. Staff does find it interesting that AURORA forecasts a lower market price overall compared to ICE's mid-C price forecast for the test period, which has increased from last year's forecast. However, the APCU's repricing methodology, discussed in Staff witness Soldavini's testimony, is meant to ensure a normalized price forecast in the October update and largely negates concerns regarding AURORA's market price simulation.

ISSUE 5. LOAD AND SALES FORECAST

Q. Please describe changes to the Company's load forecast since its October 2019 update.

A. The Company's normalized system load increased by 1 percent, or 27 aMW between from the previous October Update. It currently anticipates a load of 1,860 aMW.[6]

Q. What is driving the increase in load?

A. The increase in load is mostly driven by increases in the commercial manufacturing sectors. Most other sectors showed minimal changes from the previous APCU load forecast.

Q. Please generally describe the Company's forecast methodology.

A. Idaho Power separately forecasts each major customer class, with Industrial and Commercial sectors broken down into services and manufacturing and then further into subsets like dairy, food packaging, etc. The model for the residential class is a monthly model, while the rest of the models are annual. Historic usage, weather, and economic and demographic data are used to inform the models. The Company uses Itron's Statistically Adjusted End Use Model (SAE) to forecast residential use per customer. This model utilizes an adoption rate forecast for energy efficient items like high efficiency washing machines and low energy light bulbs to inform the model on expected usage patterns of customers in Idaho Power's service territory. The use-per-

---

[6] Idaho Power/100, Blackwell/10.

customer model is then multiplied with a customer count forecast model to achieve the total residential load.

Q. Please summarize your analysis of whether the Company's methodology is in compliance with Order No. 08-238 adopting the APCU methodology.

A. The Company has complied with Order No. 08-238 in terms of its analysis to determine the NPSE for the 2020 October Update. Staff did not perform a full model replication in order to look extensively for improvements like it would in a general rate case or IRP, but reviewed the methodology to ensure that no econometric assumptions were violated and any changes made to the model since the Company's last acknowledged IRP were reasonable and warranted.[7] Although Staff prefers monthly models for all rate classes, the use of annual models is understandable given the data inputs and their availability.

Staff inquired as to the Company's testing and model specification process and found it to be thorough and reasonable.[8] The Company uses an iterative process to identify outliers and variable selection, and in- and out-of-sample testing to identify model accuracy.

Q. Does Staff have any recommended adjustments to the Company's load forecast?

A. No. Staff finds the methodology and forecast reasonable for this APCU.

[7] Exhibit Staff/302, Gibbens/1, IPC's response to Staff DR No. 60.
[8] Exhibit Staff/302, Gibbens/4, IPC's response to Staff DR No. 59.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 366
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

February 4, 2020

WITNESS QUALIFICATION STATEMENT

NAME:	Scott Gibbens
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates, Finance and Audit
ADDRESS:	201 High St. SE Ste. 100 Salem, OR 97301-3612
EDUCATION:	Bachelor of Science, Economics, University of Oregon Masters of Science, Economics, University of Oregon
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission (Commission) since August of 2015. My current responsibilities include analysis and technical support for electric power cost recovery proceedings with a focus in model evaluation. I also handle analysis and decision making of affiliated interest and property sale filings, rate spread and rate design, as well as operational auditing and evaluation. Prior to working for the OPUC I was the operations director at Bracket LLC. My responsibilities at Bracket included quarterly financial analysis, product pricing, cost study analysis, and production streamlining. Previous to working for Bracket, I was a manager for US Bank in San Francisco where my responsibilities included coaching and team leadership, branch sales and campaign oversight, and customer experience management.

UE 366 – 2020 APCU - Responses to Staff's Data Request Nos. 55-60

TOPIC OR KEYWORD: LOAD FORECAST

STAFF'S DATA REQUEST NO. 60:

Please provide a narrative description of any load forecast model changes made since the Company's last acknowledged IRP. Please include explanation and empirical evidence of why the changes were made. If the Company produces both a short-term and long-term forecast, please only include changes to the short-term model.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 60:

The Company produces a long-term forecast that extends 20+ years into the future. The near-term or short-term sales forecast is taken directly from the early stages of the long-term sales forecast. Hence, all models are used for both short- and long-term forecasting.

To determine and/or identify potential changes or updates to the forecast models, the Company has relied on in- and out-of-sample testing techniques to determine the optimal performance and behavior of the models, considering mean absolute percentage errors (MAPE) (residuals), t and p- scores, and adjusted r squared.

Residential

The residential sales forecast is estimated using Itron's Statistically Adjusted End-Use (SAE) model. The Itron SAE model used in the 2020 forecast is essentially identical in structure to the SAE model used to prepare the 2017 IRP forecast, the Company's last acknowledged IRP. However, each year the residential SAE spreadsheets and models are updated based on the Energy Information Administration's (EIA) Annual Energy Outlook (AEO). Changes to the residential SAE during this process include, but are not limited to: updated equipment efficiency trends; updated equipment and appliance saturation trends; updated annual heating, cooling, water heating, and non-HVAC indices; as well as updated regional sales. In addition, the Company has updated the model's appliance shares to reflect appliance share estimates derived from the results of the Company's 2016 Residential End-Use Survey.

Final sales to residential retail customers are based on an equation that considers several factors affecting electricity sales to the residential sector. Residential sales are a function of Heating Degree Day (HDD) (wintertime); Cooling Degree Day (CDD) (summertime); historical energy efficiency trends in Idaho Power's residential customer base; saturation and replacement cycle of appliances; the number of service-area households; the real price of electricity; and the real price of natural gas, to name a few. Input files into the SAE framework are adapted to reflect Idaho Power's sales, customers, weather, and service-area economic drivers.

These updates to the SAE model then become part of a traditional econometric framework. For validation and refinement, the residential regression models rely on the use of indicator variables. Most indicator variables are used to explain significant deviations between actual and predicted values. These binaries, or indicators, are introduced and tested in model specification scoping to handle high errors due to extreme weather impacts, billing irregularities, seasonal deviations in residuals, and changes in use-per-customer trends and can differ from one forecast iteration to the next.

The 2017 IRP residential SAE model was estimated over the period January 2005 through June 2016 (138 adjusted observations). Three indicators were included in the final model specification, including: January months; November 2013; and June 2014.

The 2020 residential SAE model was estimated over the period January 2008 through May 2019 (137 adjusted observations). The shortened training period was used as it produced marginally better results, using the discussed statistical feedback. The estimation period begins after the housing market collapse and after the period of the Great Recession. Six statistically significant indicators were included in the final model specification, including: January months; November 2013; June 2014; October and November 2017; before 2012; and 2018 onward. The November 2013, June 2014, and October and November 2017 indicator variables were included because of the large residuals in those months, most likely due to extreme weather. The pre-2012 indicator was included to pick up the shifts in use-per-customer as evidenced by the number and magnitude of positive residuals occurring prior to 2012. The post-2018 indicator was included to pick up the shifts in use-per-customer as evidenced by the number and magnitude of negative residuals occurring in 2018 and 2019.

Irrigation

The 2017 IRP irrigation regression model was estimated over the period 1992 through 2015 (24 years). The 2017 IRP irrigation regression model included a lagged real electricity price term that was removed in the 2020 irrigation model due to a lack of significance. The 2017 IRP irrigation regression model also included an indicator variable to account for the unusually low electricity consumption in the 2001 crop year due to a voluntary load-reduction program. This indicator was eliminated in the 2020 irrigation regression model since the regression training period began in 2002. The 2020 irrigation sales forecast model was estimated over the period 2002 through 2018 (17 years). The annual maximum irrigation customer count was added as an explanatory variable and Moody's Gross Product: Agriculture, for Idaho was removed as an explanatory variable since the most recently acknowledged IRP.

Commercial and Industrial

As referenced in Staff Data Request No. 59, commercial and industrial modeling consists of a series of analytical modeling steps that begin with segmentation of industrial economic/energy use profiles. (These are: Services: Education, Health Care, Retail Goods and Services, Offices/Assembly/Lodges or Lodging, Data Centers, Warehousing and Manufacturing: Dairy, Food Packaging, Food Processing, Sugar, Base Manufacturing, Construction, Electronics/Tech, and Other/Miscellaneous).

The primary purpose for developing these models is to best understand the dynamics of causation to the components of the aggregated segments (manufacturing, service). Due to the large number of detailed segment models, the following narrative will focus on changes in the published models included in the APCU since the most recently acknowledged IRP.

Commercial Manufacturing Model: A concerted effort has been made in the current model to include a price variable in the model specification. This effort has resulted in dropping a macro variable (Gross Metro Product) in favor of agricultural activity variables. Additionally, improvements in classification algorithm resulted in reclassification of manufacturing customers to service, which changed the time-series values of the independent variable, reducing the energy value by approximately 35 percent in the manufacturing segment and increasing by an equivalent amount in the service segment. The change resulted in no significant change in adjusted R squared but a higher MAPE (from 0.57 to 1.12).

Commercial Service Model: As indicated above, better intel resulted in moving some customers to this service model from manufacturing. Additionally, the inclusion of a price variable and weather variables (HDD60 and CDD60) improved the adjusted R squared (from 0.96 to 0.99) and reduced the MAPE (from 0.71 to 0.43).

Industrial Service Model: No changes to model.

Industrial Manufacturing Model: The primary change was dropping of a model variable for Government GDP contribution in favor of manufacturing company earnings variable. While government investment in the service territory is significant, it was felt that the Moody's variable resulted in a growth level that was higher than supported by segment model indications. The change reduced the next-year forecast by approximately 4 percent. Both adjusted R squared and MAPE improved.

UE 366 – 2020 APCU - Responses to Staff's Data Request Nos. 55-59

TOPIC OR KEYWORD: LOAD FORECAST

STAFF'S DATA REQUEST NO. 59:

Please provide any model validation, model specification, or econometric assumption testing performed during the load forecasting process. For example please describe the Company's process of selecting dummy variables, testing for unit-roots and other residual or post-forecast testing performed, selection of economic drivers, data sources, etc.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 59:

The overarching philosophy for model design and development at Idaho Power is to construct multiple models that use a multiplicity of parameters, variables, and specification assumptions, which provides the diversity of results from testing and comparison. Differences in models serve to provide the basis for a solid, robust forecast. Thus, multiple models using different data providers (Moody's or Woods & Poole), annual or monthly models, econometric or SAE, etc. serve as the basis for evaluating differences, output, and underlying sources of differences.

Data sources used by the Company include the National Weather Service for weather data. Note that the weather stations that Idaho Power uses have not changed. The forecast models are largely tied to economic data that is primarily sourced from Moody's Analytics and in certain cases Woods and Poole Economics. Additionally, the Company uses economic data from major economic data collectors such as the U.S. Census Bureau and Bureau of Labor Statistics, to name a few. The national, state, metropolitan service area, and county economic and demographic projections are tailored to Idaho Power's service area using an in-house historical economic database. Company specific energy data that has been reconciled to official billing and metering intervals is utilized as well.

Primary validation for the regression models would sit within the model specifications and the use of indicator variables. Most indicator variables are used to explain significant deviations between actual and predicted values. The mean absolute percentage error is a primary driver in the determination and refinement of model performance. The indicators are introduced and tested each forecast iteration period in the model specification to handle high errors due to extreme weather impacts, billing irregularities, seasonal deviations in residuals, and changes in use-per-customer trends. Inclusion, addition, or exclusion of indicator variables can potentially differ by year depending on residual testing results. The Company does not incorporate any unit-root functionality into its regression models. However, use of differing training periods within the regressions has been the Company's primary solution to the issues that would otherwise be covered with unit-roots.

An additional element to econometric modeling philosophy for the Company is to specify different segments or subsets of the underlying rate classes toward testing economic or otherwise homogenic behavior. This is most notable in the commercial and industrial classes. For example, the industrial class is segmented into 14 separate segments of independent variables (e.g., dairy, consumer food packaging, sugar manufacturing, etc.). The value of this is to understand the causal variable dynamics, which include exposing non-stationarity (as an aside, this is a desirable condition when modeling birth/death influences), residual distribution/impact, and other statistical influences. The segmentation provides insight for specifying more aggregate class models particularly toward developing transformations for independent variables, which tend to support the development of improved stability in the models. Ultimately, the final class population for forecasting commercial and industrial is comprised of manufacturing and service segments for both commercial and industrial. Additional discussion is provided in the Company's response to Staff's Request No. 60.

The Company integrates an SAE model framework for residential customers. Structural changes to the end-use framework are tested through a third party. Any regression testing or validation of the final residential output follows the same philosophy as noted above. Additional discussion is provided in the Company's response to Staff's Request No. 60.

CASE: UE 366
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

REDACTED
February 4, 2020

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

A. My name is Kathy Zarate. I am a Utility Economist employed in the Energy Rates, Finance, and Audit Division 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 summarize analysis and recommendations on certain issue regarding Idaho Power Company's 2020 Annual Power Cost Update, Docket No. UE 366.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

- Staff/401: Witness Qualification Statement
- Staff/402: Idaho Power's Responses to Staff Data Request Nos. 39, 52, 53.
- Staff/403: Idaho Power's Confidential Responses to Staff Data Request Nos. 24, 27, 30.
- Staff/404: Staff's Work paper

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. WHEELING

Q. Please discuss wheeling expenses.

A. Wheeling expenses are Idaho Power's costs to transmit electricity over transmission facilities. Often, wheeling expenses are net of wheeling revenues, which are revenues received from the use of Idaho Power's transmission system by third parties.

Q. Are wheeling expenses included in the Idaho Power filing?

A. No. According the Company's response to Staff Data Request No. 53, Idaho Power states that the APUC methodology does not include wheeling costs or revenues. In reviewing the application, Staff found reference to transmission expenses in the Exhibit Idaho Power/105, Blackwell/1. In the table appearing on that page, transmission costs are removed as a component of surplus sales with line 28 of that table expressing surplus revenue net of transmission costs (excludes effect of transmission costs).

Q. Do you have an adjustment for wheeling?

A. No. My recommendation is based on the company **assertion** the wheeling cost are not a component of the APUC per Commission order.

ISSUE 2. FORCED OUTAGE RATES AND SCHEDULED MAINTENANCE OUTAGES

Q. Please describe forced outages and how IPCO calculated its forced outage rate?

A. The forced outage rate is the proportion of forced outage hours to the total hours the plant is available for generation. Forced outages occur when a plant is taken offline for maintenance outside of normal prescheduled timing. Idaho Power calculates its forecast forced outage rate based upon a three-year historical average of forced outage rates.

Q. What did you review?

A. Staff reviewed the pattern of actual forced outage rates for the Company's plants to see if there were any swings in the forced outage rates that perhaps should be excluded from the analysis as unrepresentative or non-normalized. This is consistent with how Staff reviews forced outage rates in general.

Q. What did your review conclude?

A. While there were some large swings in forced outage rates, Staff did not find any to be significant enough to require exclusion from the calculation of the three-year moving average forced outage rate for this docket. Staff did notice that the Boardman Coal Plant (Boardman) had some large swings; however, these outages can be found in the older historical availability patterns of Boardman and consistent with the data provided by PGE in its annual power cost filing.

Q. Moving on to planned maintenance, did you also request that Idaho Power provide its prior projections of its forced and schedule outages?

A. Yes, the Company's responses to Staff Data Request No. 39 is summarized in Table 1 below and is provided in full in Exhibit Staff/402.

Table 1

Idaho Power Projected Scheduled Outages	2015 APCU		2016 APCU		2017 APCU		2018 APCU		2019 APCU		2020 APCU*	
	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End
Bridger Unit #1	4/18/2015	4/21/2015	4/14/2016	4/19/2016	3/31/2017	4/2/2017	4/7/2018	5/25/2018	4/23/2019	4/25/2019		
Bridger Unit #2	4/12/2015	4/17/2015	4/10/2016	4/13/2016	4/8/2017	5/26/2017	4/1/2018	4/1/2018	4/13/2019	4/17/2019		
Bridger Unit #3	9/5/2015	11/5/2015	4/18/2016	4/21/2016			4/3/2018	4/5/2018	4/27/2019	5/31/2019		
Bridger Unit #4	4/22/2015	4/25/2015	9/3/2016	11/3/2016					4/19/2019	4/21/2019	4/25/2020	5/30/2020
Boardman	4/18/2015	6/6/2015	4/15/2016	5/16/2016	4/8/2017	5/21/2017	4/21/2018	5/4/2018	4/27/2019	5/24/2019		
Valmy Unit #1			4/1/2016	4/18/2016	4/1/2017	4/8/2017						
Valmy Unit #2	4/4/2015	5/18/2015	4/23/2016	5/1/2016	4/10/2017	4/17/2017	4/7/2018	4/20/2018				

*The scheduled outage included in the 2020 APCU forecast is for yearly planned maintenance.

Q. What does Table 1 show?

A. Table 1 show that 2020 will be unusual in that minimal maintenance is scheduled as compared to other years. If an average is being used, that average will reflect greater amounts of maintenance occurring than will actually occur in 2020. This means that actual power costs will likely be below forecast.

Q. Why is that?

A. Assuming average scheduled maintenance, the Jim Bridger Power Plant (Jim Bridger) would be less available to produce power than will actually be the case in 2020. Assuming Jim Bridger is "in the money", meaning having operating cost less than market or lower cost than some other Idaho Power generation, then the APUC will project higher costs than would otherwise occur.

Q. Does this cause concern?

A. Not necessarily. As long as the averaging approach is consistently used over time, years of less scheduled maintenance will offset years with higher scheduled maintenance. Using an averaging approach consistently means that in some years Jim Bridger will in actuality be down for schedule maintenance more than average, and on other years like in this test period, Jim Bridger will be down less than the average scheduled maintenance. In the former case, the APCU will project power costs less than actual all else being equal. In the latter case, as is in this case, the APCU will project power costs that will be higher than actual all else being equal. This results in a normalized forecast for every year.

ISSUE 3. PURPA

Q. How are PURPA contracts incorporated into the APUC?

A. In forecasting power costs for a future test year, part of the power cost forecast is new Qualifying Facilities (QFs) coming on-line. The date at which a new QF is forecast to begin commercial operation during the future test period could have significant impact on the amount of generation forecast from these new QFs. Power costs also include a forecast of power production from existing QFs, but my testimony will focus on the issue of handling new QFs. For example, if Idaho Power forecasts a Commercial Operation Date (COD) of January 1, 2021, in the test year, and then the COD is delayed by ten months, customers will pay for an entire year of generation from that QF while in fact the QF was not in operation for ten months of year. Idaho Power would have to replace the purchased power assumed to be available from the QF. It would therefore be possible that market purchases or utility operation of its existing resources could be cheaper than the QF power. This creates a discrepancy between what was forecast and actual power costs.

Q. Did Staff ask Idaho Power how its projections of QF purchased power costs compare to actuals?

A. Yes. Staff asked Idaho Power to provide both its actual and projected QF purchase power costs for the years 2015 through 2019. Staff created Table 2, below, based on the information provided by Idaho Power. (Exhibit Staff/403, Idaho Power Response to Staff Data Request No. 24).

Table 2-Confidential

[Begin Confidential]

[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[End Confidential]

Q. What do you conclude from Table 2?

A. In the case of Qualifying Facility purchases, Idaho Power has consistently overestimated its QF purchase power cost. Over the 2015 through 2018 time-period, the average level of overestimation is 19 percent. Given that Idaho Power has not identified a change in approach of estimating QF costs, there is no reason to assume that the consistent overestimation has been corrected. (See Staff/402, Idaho Power Response to Staff Data Request No. 53.)

Q. What does this imply with regards to an adjustment?

A. Idaho Power estimates total QF power purchase costs of $223.5 million. Recalculating that cost using the conservative amount present in the most recent over-estimation amount of 13 percent, rather than the historical average amount of 19 percent, results in a downward adjustment of $29.06 million. Idaho Power's Oregon allocation factor is approximately 4.63 percent. Applying 4.63 percent to $29.06 million leads to a downward adjustment of $1.35 million on an Oregon allocated basis.

Q. The forecast error can come from a combination of overestimation of QF generation or over-estimating the purchase price. Do you propose to modify your adjustment for the amount of error in QF costs by over estimating generation?

A. No. The reason is supported from the Table 3 below; again, the information is taken from the Company's response to Staff Data Request No. 24. From Table 3 we can observe that for the 2018-2019 time period actual generation was greater than project generation. Since total cost equals price per kWh multiplied by kWh, any overestimation of costs (forecast minus actual) for that time period could not be the result of generation-related because actual generation exceeded forecasted generation.

Table 3-Confidential

[Begin Confidential]

[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[End Confidential]

Q. What does table 3 shows?

A. Table 3 shows that in the most recent APCU, April 2018 through March 2019, Idaho Power actually under-forecasted QF generation while still over-forecasting QF purchase power cost by 13 percent. Therefore, no adjustment is needed relative to an over-forecast of QF generation because no QF forecast of QF power purchase occurred in the 13% over forecasting of power cost expenses.

ISSUE 4. WIND FORESCAST

Q. Please provide a background for this issue.

A. To forecast wind generation for the April 2020 - March 2021 test year Idaho Power uses monthly generation estimates that are the rolling average of historical monthly generation for the most recent five years. If historical generation is not available, generation estimates created during project development are used.

Capacity factors are calculated based on the generation forecast divided by the maximum generation capability during a month. An example is included in the protected information attachment provided in response from the company to Staff Data request No. 27. Is summarized in table 4 below and is provided in full in Exhibit Staff/403.

Table 4-Confidential

[Begin Confidential]

[redacted]

[End Confidential]

Q. What is Staff's recommendation for this issue?

A. Staff does not have any adjustment this time. The Company has followed the commission approved forecast methodology and staff finds no reason to make an alternate recommendation at this time.

ISSUE 5. SOLAR FORECAST AND SHAPE

Q. Please provide a narrative explanation of this Issue.

A. According to Idaho Power the solar shape of generation is calculated from reviewing historic hourly generation information. Idaho Power determines hourly capacity factors by dividing total actual hourly generation for a previous year by the maximum generation capacity and then applies these capacity factors to the forecast of monthly solar generation for the test year to determine a 12-month x 24-hour shape. The Company's responses to Staff Data Request No. 52 and is provided in full in Exhibit Staff/402.

Q. Does Idaho Power develop shapes for each individual project?

A. No, Idaho Power develops the shape by analyzing all of its solar generation, not any individual project. (See Exhibit Staff/403, Company's response to Staff Data request No. 30.)

Table 5 below as an example on the test year.

Table 5 - Confidential

[Begin Confidential]

[redacted]

[End Confidential]

Q. Is this a reasonable approach?

A. Yes, Idaho Power's calculation of summing all generation and capacity using the aggregate values, this is a reasonable approach. In UE 356, Staff recommended that utility use more than one year's of data to better ensure that the shape reflects a more representative shape in case a single year has a distorted shape. The Company in this docket has used more than one year's data to derive the shape and therefore is consistent with prior staff recommendations.[1]

Q. Does this conclude your opening testimony?

A. Yes.

[1] UE 356, Exhibit Staff/200, Sodavini/8, lines 3-15.

CASE: UE 366
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

February 4, 2020

WITNESS QUALIFICATIONS STATEMENT

NAME:	Kathy Zarate
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Economist Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Arts, Economics Oregon State University, Corvallis, Oregon Bachelor Degree in Law Republic University, Santiago, Chile

EXPERIENCE:

I have been employed by the Public Utility Commission of Oregon since April 2016, with my current position being a Utility Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of regulatory issues such as review of affiliated interest filings, property sales applications and rate proposals.

I have approximately 10 years of professional experience in contracting and audit review work, including:

- Six years as contract specialist for 3 Com, Santiago, Chile, with responsibilities including coordinating and preparing contracts with resellers, reviewing company books and records, coordinating logistics in business delivery, and investigating property theft.

CASE: UE 366
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

February 4, 2020

TOPIC OR KEYWORD: FORCED AND SCHEDULED OUTAGES

STAFF'S DATA REQUEST NO. 39:

Please provide the following information in Excel format:

a. Projected scheduled outage rates for each unit, as reflected in final rates for each test year from 2015 through 2020.
b. Actual scheduled outage rates for each unit, for each test year from 2015 through 2019.
c. The dates, duration, and cause of scheduled outages occurring between 2015 and 2019.
d. The dates, duration, and cause of scheduled outages forecasted for 2020.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 39:

Please see the attachment provided in response to this request.

TOPIC OR KEYWORD: PURPA

STAFF'S DATA REQUEST NO. 52:

Describe the steps taken by Idaho Power to ensure the accuracy of its forecast, A) Solar and B) Solar.

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

Idaho Power's cogeneration and small power production ("CSPP") forecast included in the APCU is based on the average monthly output of historical actual generation, up to five years, from PURPA QFs under contract with Idaho Power, and contract rates that are approved by the Public Utility Commission of Oregon ("Commission"). Where historical generation is not available from a QF that is under contract, but not online, Idaho Power relies on estimates of generation provided by the QF in accordance with the QF's contract. Idaho Power reviews the estimates provided by the QFs to ensure they are reasonable and consistent with other projects of the same resource type, facility characteristics, size, and location of the QF. In summary, the development of Idaho Power's CSPP forecast is a prescriptive process that relies on contract rates approved by the Commission and actual historical generation, when available, or generation estimates provided by the QF.

TOPIC OR KEYWORD: TRANSITION WHEELING REVENUES AND COSTS

STAFF'S DATA REQUEST NO. 53:

What Percentage of each of 2017, 2018 and 2020 applicable actual and projected wheeling costs are impacted by changes in tax law and FERC show cause therefor?

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 53:

The Open Access Transmission Tariff ("OATT") rates Idaho Power pays for transmission services are determined by Federal Energy Regulatory Commission-approved methodologies specific to each transmission provider. Therefore, to determine whether these entities incorporated tax law changes or other updates into their OATT rates would require Idaho Power to perform a comprehensive review of each entity's OATT rate methodology for each of the requested years. As a result, Idaho Power has not quantified the requested information.

Please note, the Company's approved APCU methodology does not include costs or revenues associated with transmission wheeling. Market purchases and sales are re-priced based on Mid-Columbia forward market electricity prices. [1]

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

CASE: UE 366
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 403

Exhibits in Support
Of Opening Testimony

February 4, 2020

TOPIC OR KEYWORD: PURPA or QFs

<u>STAFF'S DATA REQUEST NO. 24</u>:

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 2015 through 2020. 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 2015 through 2019. 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 2015 through 2019.**

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 24</u>:

Please see the protected information attachment provided in response to this request.

The attachment provided in response to this Request contains protected information and will be provided in accordance with General Protective Order No. 19-379.

UE 366 IPC TO STAFF DR 024 CONF ATTACH

IS IN ELECTRONIC FORMAT

AND

IS CONFIDENTIAL - SUBJECT TO

PROTECTIVE ORDER NO. 19-379

TOPIC OR KEYWORD: WIND FORECAST AND CAPACITY FACTORS

STAFF'S DATA REQUEST NO. 27:

Please provide a narrative explanation of how Idaho Power calculated its forecast of wind generation and capacity factors for the 2020 test year. Include a worked example in Excel format, with all formulas and cells intact.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 27:

The forecast of wind generation for the April 2020 - March 2021 test year is created in the same manner that it is developed for all other PURPA resource types. The forecast consists of monthly generation estimates that are the rolling average of historical monthly generation, up to the most recent five years. If historical generation is not available, generation estimates from the projects are used.

Capacity factors are calculated based on the generation forecast divided by the maximum generation capability during a month. An example is included in the protected information attachment provided in response to this request.

The attachment provided in response to this Request contains protected information and will be provided in accordance with General Protective Order No. 19-379.

UE 366 IPC TO STAFF DR 027 CONF ATTACH

IS IN ELECTRONIC FORMAT

AND

IS CONFIDENTIAL - SUBJECT TO

PROTECTIVE ORDER NO. 19-379

TOPIC OR KEYWORD: SOLAR FORECAST AND SHAPE

STAFF'S DATA REQUEST NO. 30:

Please provide a narrative explanation of how Idaho Power calculated its forecast of solar generation and shape for the 2020 test year. Include a worked example in Excel format, with all formulas and cells intact.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 30:

The forecast of solar generation for the April 2020 - March 2021 test year is created in the same manner that it is developed for all other PURPA resource types. The forecast consists of monthly generation estimates that are the rolling average of historical monthly generation, up to the most recent five years. If historical generation is not available, generation estimates from projects are used. An example is included in the protected information attachment provided with the response to this request.

For the solar shape, Idaho Power determines hourly capacity factors by dividing total actual hourly generation for the previous year by the maximum generation capacity and then applies these capacity factors to the forecast of monthly solar generation for the test year to determine a 12-month x 24-hour shape. An example is included in the protected information attachment provided with the response to this request.

The attachment provided in response to this Request contains protected information and will be provided in accordance with General Protective Order No. 19-379.

UE 366 IPC TO STAFF DR 030 CONF ATTACH

IS IN ELECTRONIC FORMAT

AND

IS CONFIDENTIAL - SUBJECT TO

PROTECTIVE ORDER NO. 19-379

CASE: UE 366
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 404

Exhibits in Support
Of Opening Testimony

February 4, 2020

STAFF EXHIBIT 404

IS IN ELECTRONIC FORMAT

AND

IS CONFIDENTIAL - SUBJECT TO

PROTECTIVE ORDER NO. 19-379

CERTIFICATE OF SERVICE

UE 366

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 4th day February, 2020 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
Telephone: (503) 378-5763

UE 366 SERVICE LIST

CUB	
OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY, STE 400 PORTLAND OR 97205 dockets@oregoncub.org
WILLIAM GEHRKE (C) OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY STE 400 PORTLAND OR 97206 will@oregoncub.org
MICHAEL GOETZ (C) OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY STE 400 PORTLAND OR 97205 mike@oregoncub.org
IDAHO POWER	
IDAHO POWER COMPANY	PO BOX 70 BOISE ID 83707-0070 dockets@idahopower.com
ADAM LOWNEY (C) MCDOWELL RACKNER & GIBSON PC	419 SW 11TH AVE, STE 400 PORTLAND OR 97205 dockets@mrg-law.com; adam@mrg-law.com
LISA D NORDSTROM (C) IDAHO POWER COMPANY	PO BOX 70 BOISE ID 83707-0070 lnordstrom@idahopower.com; dockets@idahopower.com
STAFF	
STEPHANIE S ANDRUS (C) PUC STAFF--DEPARTMENT OF JUSTICE	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@state.or.us
MOYA ENRIGHT (C) PUBLIC UTILITY COMMISSION OF OREGON	PO BOX 1088 SALEM OR 97308 moya.enright@state.or.us
SCOTT GIBBENS (C) PUBLIC UTILITY COMMISSION OF OREGON	201 HIGH ST SE SALEM OR 97301 scott.gibbens@state.or.us