CASE: UE 314
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

January 31, 2017

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

A. My name is Scott Gibbens. I am a Senior 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/101.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present some of Staff's analysis and concerns regarding the 2016 October Update, the first portion of Idaho Power Company's (IPC, Idaho Power or Company) Annual Power Cost Update (APCU). My testimony will cover: (1) compliance of the filing with applicable Commission rules and Orders, (2) the 'hybrid' model update and (3) AURORA Re-pricing. Lance Kaufman (Staff/200) and Deborah Glosser (Staff/300) will present other portions of Staff's analyses.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/101, consisting of one page, and Exhibit Staff/102, consisting of two pages.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, FILING AND COMPLIANCE

Q. Did the filing conform to applicable Commission rules and Orders?

A. Yes, the filing follows all of the applicable rules and orders. Commission Order No. 08-238 sets forth the majority of requirements regarding the APCU October Update. The Order requires IPC to utilize the AURORA model to determine the estimated net power supply expense and reprice the wholesale electric prices. In addition, the Order stipulates inputs to be updated annually.

Further, the Company's filing is consistent with the Stipulation adopted by the Commission in its Order No. 16-206 (Docket UE 301).

Q. Please describe what inputs the Company may update.

A. Per Order 08-238, the Company updated the following inputs:

a. Fueling prices and transportation costs;

b. Planned outages and forced outage rates;

c. Heat rates;

d. Forecast of Normalized Load and Normalized Sales;

e. Contracts for wholesale power and power purchases and sales;

f. Forward price curve;

g. PURPA contract expenses;

h. The Oregon state allocation factor; and

i. Wheeling Expense.

Q. Did Staff check the validity and reasonableness of the updated input parameters?

A. Yes, Staff reviewed the updated inputs used in the October Update. In general, the values seem reasonable and in line with both previous filings and last year's actual parameter values. Potential issues associated with input parameters are discussed later in my testimony.

Q. Did IPC perform the prescribed calculations properly?

A. Yes, to this point in Staff's analysis, Staff has found no errors associated with the calculations used in the APCU. The Company adhered to all pertinent Commission orders.

Q. How does this projection compare with last year's actual parameter values?

A. Historically, the 2015 calendar year was a poor hydro year. The hydro power generated was approximately 30 percent lower than the mean of the previous 87 years. This resulted in higher generation costs among coal, natural gas and purchased power. The total "net power supply expense" (NPSE) in the Company's most recent true-up (UE 305) was approximately $388,073,000 for the 2015 calendar year. The October Update predicts an April-March NPSE of $382,100,000. Staff believes the roughly two percent difference in actual vs forecast is understandable given the hydro conditions.

Q. Did the Company propose any modeling changes in the APCU?

A. No, in this year's filing, IPC did not make any proposed model changes.

ISSUE 2, HYBRID MODEL

Q. Please provide a background of the hybrid model.

A. In UE 301, the parties agreed that a model change was necessary in order to properly model Oil, Handling, Administrative, and General (OHAG) expenses.[1] Due to a disparity in the dispatch amounts between the Company and its operating partners, a portion of OHAG was not being accurately estimated and recovered in the APCU.[2] According to the Company's UE 301 testimony, OHAG expenses were being split based on the ownership percentage, but the former model was only capturing the cost that IPC incurred when it made a dispatch decision.[3] The cost incurred when IPC's plant partner decided to run the plant was not included in the model. Previously, the percentage of power dispatched at a plant closely followed the actual ownership percentage, however when those two percentages diverged, stranded costs became an issue. In adopting the parties' Stipulation in UE 301, the Commission ordered the parties to review the model change in order to fully evaluate the impacts and ensure the new "hybrid model" (Hybrid Model) was sufficient to set rates. *See* Commission Order 16-206, adopting the Stipulation attached to the Order as Appendix A.

Q. Did the Hybrid Model improve the APCU, and if so, how?

[1] See Order No. 16-206, Appendix A, pages 6-8.
[2] Pursuant to OAR 860-001-0460, for the Opening Comments submitted by all Staff members, Staff asks the Commission to take official notice of materials that were submitted in other Commission dockets.
[3] See UE 301, Idaho Power/100, Noe/8, pages 7-9.

A. Yes, the Hybrid Model has improved the APCU. As previously mentioned, the former model included only the OHAG cost that Idaho Power incurred when it made the decision to dispatch the plant. Idaho Power's initial proposal removed this cost from AURORA, and then added an estimate of total OHAG costs after AURORA had run. Because AURORA uses the information included as inputs to calculate the most efficient dispatch of IPC's resources to estimate NVPC, any information left out would hinder AURORA's ability to optimize power costs. In order to have the most complete information for AURORA to run an optimization, the parties in UE 301 agreed to include the incremental cost associated with dispatching a coal plant in AURORA. The estimated fixed portion of cost resulting from IPC's plant partners dispatching decisions is added after AURORA has run. The goal was to both provide AURORA with the most complete information on which to optimize, and to also ensure that Idaho Power recovered all costs associated with OHAG.

Q. Has Staff reviewed the Hybrid Model?

A. Yes. On January 12, 2017, all parties attended a workshop on the Hybrid Model. IPC provided a review of the Model, and answered questions posed by Staff and CUB. Staff has also reviewed the impact of the Hybrid Model on NVPC and examined ways to improve the modeling or other outlets to remedy the problem.

Q. What were the results of Staff's analysis?

A. While Staff found several benefits to the Hybrid Model, Staff continues to have some concerns about it. Looking at how other utilities handle the OHAG costs, one potential alternative Staff examined was Portland General Electric Company's approach of including OHAG costs in general rate case filings (GRC), collected in base rates and not in annual power costs filings.

Q. What were the benefits that Staff found?

A. The main benefit of the Hybrid Model is that it provides AURORA with a complete picture of the costs associated with dispatch decisions. This allows the AURORA program to efficiently dispatch and will provide an ideal benchmark for IPC to achieve in its actual dispatch decisions. The Hybrid Model also ensures that IPC will recoup all of its costs using a relatively straightforward model. The Model also produces predictable and stable costs for OHAG as evidenced in Table 1 shown immediately below:

Table 1

	UE 301 Per-unit Cost (as filed)	UE 301 Per-unit Cost Hybrid (as filed)	UE 301 Per-unit Cost Hybrid (as settled)	UE 314 Per-unit Cost (as filed)
Bridger	$28.79 per MWh	$29.00 per MWh	$29.00 per MWh	$32.53 per MWh
Boardman	$25.32 per MWh	$25.46 per MWh	$25.46 per MWh	$28.06 per MWh
Valmy	$47.18 per MWh	$51.86 per MWh	$39.59 per MWh*	$49.91 per MWh

*Per-unit cost decrease due to settlement agreement

As evident in Table 1, the per-unit cost of the Hybrid Model is consistent with the previous model proposed by Idaho Power, and does not change significantly between filings.

Q. What issues does Staff have with the new model?

A. Staff has identified three possible issues involving the Hybrid Model:

1) The forecast used to estimate total OHAG expenditures;

2) The Model continues to rely on a post-optimization adjustment; and

3) The recovery of shared OHAG costs may not be best dealt with in the APCU.

Q. Please describe Staff's first issue involving the forecast of total OHAG.

A. The OHAG costs that are eventually included in the APCU are entirely based upon a forecast of expected OHAG costs at each coal plant. The forecast is not updated on an annual basis, and has been updated once in the last six years. In response to Staff DR 31[4], Idaho Power stated that the process for forecasting OHAG followed these four steps:

(1) Review of actual historical cost data.

(2) Identification of trends in actual data and review of potential known changes that could impact future OHAG expenses.

(3) Determination of whether the forecast should be updated, or if expected changes do not warrant a modification.

(4) If changes are deemed necessary, the appropriate modification is determined based on the driver of the change. For example, if the change is made due to a general upward trend in OHAG costs, the modified forecast will be updated to reflect this trend.

IPC indicated that there is no particular number of years used as a basis in determining a cost trend or average baseline for the forecast. Staff believes that the forecast needs to be formulaic, transparent and follow a systematic approach, incorporating historical data and any prevalent trends. In analyzing the current forecast, Staff reviewed how the historical estimation has performed against actual costs.

Q. How did the forecast OHAG compare to actuals?

[4] See Staff Exhibit Gibbens/102

A. As shown in Table 2, Idaho Power under forecast OHAG for the years 2010-2013. In 2014, when they adjusted the OHAG forecast, the actuals were less than the forecast for the following two years.

Table 2

	Bridger		Boardman		Valmy		Under/Over Forecast
Year	Actual	Forecast	Actual	Forecast	Actual	Forecast	
2010	$4,099,423	$3,038,400	$294,481	$356,400	$3,075,086	$2,874,000	-$1,200,189
2011	$3,899,558	$3,038,400	$452,780	$356,400	$3,991,881	$2,874,000	-$2,075,419
2012	$3,689,978	$3,038,400	$564,995	$356,400	$4,976,490	$2,874,000	-$2,962,662
2013	$3,692,961	$3,038,400	$248,543	$356,400	$5,496,435	$2,874,000	-$3,169,139
2014	$2,986,505	$3,538,400	$321,642	$356,400	$4,556,084	$4,085,000	$115,569
2015	$3,099,137	$3,538,400	$182,786	$356,400	$4,513,876	$4,085,000	$184,001

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

A. Staff believes that the forecast should be updated annually. It should be based on a three-year historical average of actual OHAG costs, with a growth (reduction) rate equal to the five-year historical average growth (reduction) rate. The update to the forecast should be included in the March update of NVPC so as to include the most recent annual data. If implemented annually, this process will reduce otherwise larger swings in OHAG expense estimation, and provide a formulaic approach to cost forecasting.

Q. Why does Staff have an issue with a post-AURORA adjustment?

A. While the Hybrid Model improves the information included in AURORA's optimization, it is still not complete. Any time that IPC decides to dispatch a coal unit, it incurs the cost of incremental OHAG but the Company reduces the subsidization it is providing to its operating partner in the form of shared OHAG expense. When Idaho Power dispatches a coal plant, it is only actually paying a percentage of the OHAG cost that is incurred. When those units are right on the margin, AURORA would not dispatch the coal plant when in fact the optimal decision may be to dispatch the facility.

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

A. To this point, the parties have not identified a possible solution to this issue. However, for the present UE 314 proceeding, Staff believes that producing an accurate estimate of OHAG costs in the current Hybrid Model would result in a very small difference in current and optimal modeling.

Q. Please explain where Staff believes that OHAG costs should be recovered.

A. In reviewing the potential improvements and alterations to the Hybrid Model, Staff reviewed the treatment by other Oregon regulated electric utilities of OHAG costs. Staff notes that PGE, who is an ownership partner of the Boardman coal plant, does not include its OHAG costs in its power cost filings. Instead, PGE recovers these costs in base rates, which are adjusted during every general rate case (GRC). Like the Hybrid Model, PGE includes the incremental OHAG costs in its MONET economic optimization model. But instead of performing a post-model adjustment to include the total amount, PGE completely removes the OHAG costs from power costs. Ultimately, this simplifies the model and power cost filing. Further, neither PGE nor PacifiCorp attempt to recoup costs which are the result of an operating partner's dispatch decision. Idaho Power initially proposed the OHAG adjustment, due to the disparity between ownership percentage and dispatch percentage at the Valmy plant. This results in Idaho Power customers effectively paying for costs for which they receive no benefit.

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

A. Ultimately, Staff recommends the OHAG costs should continue to be included in the APCU. Staff notes that Idaho Power historically has not come in for a GRC as often as PGE. Thus, any change in OHAG costs over time would not be corrected as quickly as in the APCU because these costs are for PGE due to the relative frequency of PGE's rate cases. Further, a GRC-based method would increase the importance and potential risk of correctly forecasting OHAG costs. Although Staff recognizes the arguments first posited by the Citizens'Utility Board of Oregon (CUB) in UE 301,[5] the shared OHAG costs stem from economic conditions which are out of IPC's control as well as contractual obligations which are common place in joint operating agreements for coal plants. Idaho Power, who is jointly responsible for the operating expenses at Boardman and Bridger, has not requested additional adjustments for minimum coal contracts like its operating partners PGE and PacifiCorp have in their respective power cost filings.

Staff views the minimum contracts and OHAG issues as all stemming from the same core problem. The coal plant operations and contracts were implemented as base load units. As natural gas prices have declined, and must-take

[5] In UE 301, at CUB/100, McGovern/16, CUB argues that FERC ruled that Idaho Power should not include PacifiCorp based O&M in its formula rate and thus shared OHAG costs should not be recoverable by Idaho Power rate payers.

resources have increased, coal fired plants have become less economical to run.

Q. Does Staff continue to support the Hybrid Model?

A. Yes, Staff recommends the changes reflected by the Hybrid Model to the forecast of total OHAG costs be implemented to improve transparency, and Idaho Power should continue to utilize the Hybrid Model to estimate net variable power costs.

ISSUE 3, AURORA RE-PRICING

Q. What is Staff's concern with AURORA re-pricing?

A. Following a similar logic as the Hybrid Model, Staff views the re-pricing in AURORA as an uneconomic post-run adjustment. AURORA is not optimizing on the actual information that ends up included in the APCU, meaning with more complete information, AURORA would be better able to estimate a true benchmark of NVPC.

Q. Can you explain how the re-pricing works?

A. Idaho Power/100, Blackwell/12 through Blackwell/14, contains a thorough explanation of the re-pricing methodology. I will briefly explain the process and Staff's concerns.

AURORA simulates wholesale power markets at every major hub in which Idaho Power transacts for every hour of the year.. The result is a purchase and sale price which AURORA uses to find the lowest cost means to meet Idaho Power's projected load. During certain times, this may mean purchasing power from the market, and at other times, it may mean producing excess power, which it can then sell to the market for a profit, thus lowering power costs. After this has occurred, and AURORA has calculated the lowest possible cost to meet load, the purchases and sales transactions are then re-priced using a forward price curve. For example, if in the month of December, AURORA estimated that IPC would sell 100,000 MWh of power to the market, that amount is multiplied by the average price for power based upon the forward price curve in the month of December. The curve itself is made up of an average of daily prices curves that are collected by IPC for two years into the future. A year's worth of inflation is removed from the prices to estimate what the prices will be during the month in which the transactions are expected to take place.

Q. Why does IPC use a price curve from two years into the future?

A. The use of any forward price curve in conjunction with AURORA modeled prices was originally implemented by the Commission in Order No. 05-871. The original intent of using a two-year forward price curve was so that the prices included in the APCU would be normalized, and devoid of any of the effects current conditions may have on prices.[6]

Q. Please explain Staff's concerns in more detail.

A. Staff believes that the use of normalized prices which are derived from a third-party source present an unbiased and fair estimation of normal prices which Idaho Power will encounter over the course of the year. However, the optimization which AURORA performs is muddled by post-run adjustment performed in the re-pricing. If AURORA were to include the forward price curve used to re-price in its calculation of NVPC, the resulting market transactions and net variable power costs would be different. Further, AURORA would estimate NVPC's that are lower than what the current process produces. In certain circumstances, AURORA would have IPC produce more power to sell for a profit, and in others it would have IPC produce less when the market price is lower than IPC's cost of production.

[6] See Idaho Power/100/Youngblood/11, beginning at line 19 in UE 194.

Q. Why isn't the forward price curve included as an input to AURORA?

A. To this point, Idaho Power has not been able to identify a means to include market price as an input to AURORA. A large portion of the value that AURORA provides is its ability to simulate all of the markets of which Idaho Power may be a part. The program is simply not meant to take price as an input. As such, it is not possible to have AURORA consider the forward price curve in its economic dispatch.

Q. Does Staff view the use of AURORA's simulated prices as an improvement?

A. As mentioned earlier, Staff believes that the Commissions original decision to normalize prices from a third-party source provides an objective means to estimate the market. As shown in the figures below, the simulated price and the forward price curve largely follow the same trend, however AURORA's price is subject to some short term swings presumably the result of 'current conditions.'

Figure 1

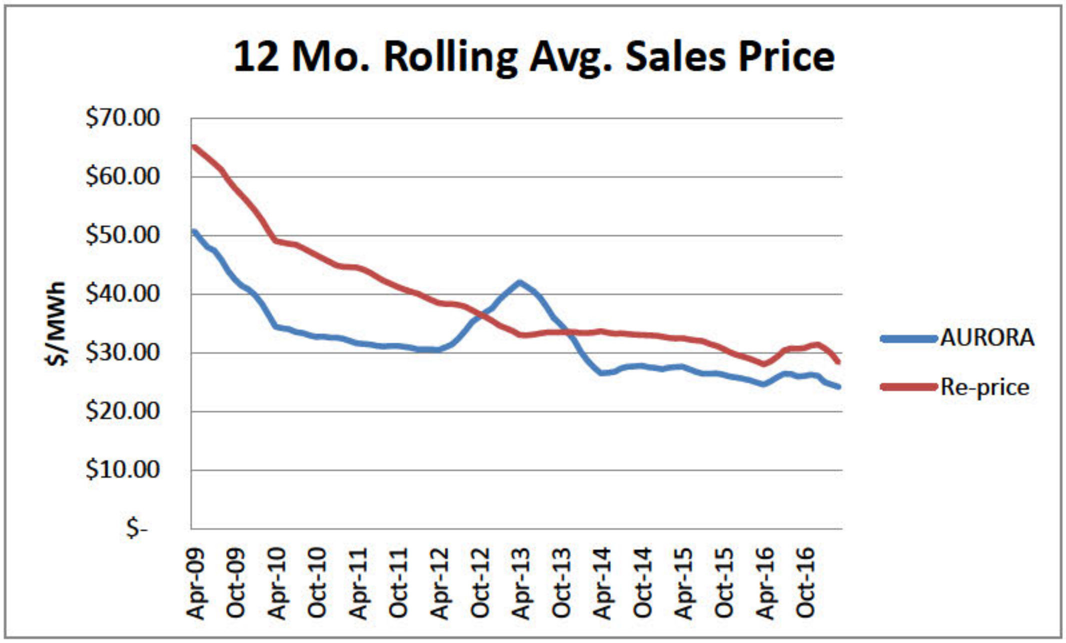
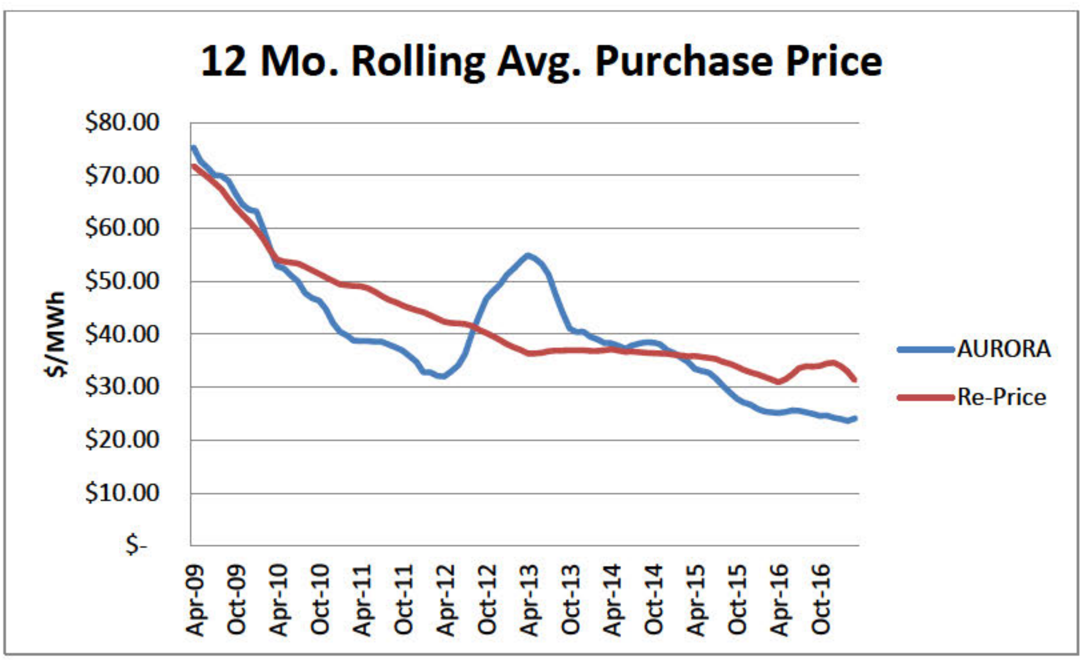


Figure 2



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

A. Staff proposes no changes to the methodology at this time. If in the future AURORA has the ability to take price as an input, Staff believes the Commission should consider directing Idaho Power to do so.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UE 314
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

January 31, 2017

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.

CASE: UE 314
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

January 31, 2017

<u>STAFF'S DATA REQUEST NO. 31</u>:

Regarding Staff DR 7, please provide further information regarding the OHAG forecast. Specifically:

a. What is the step-by-step process for formulating the forecast?
b. Are there a particular number of historical years used as a basis?
c. How is a historical trend incorporated?
d. Please identify the years when the forecast was updated (e.g. 2002, 2013, etc.).
e. Please provide the reason or material change that was identified that prompted the update.
f. How often is the forecast reviewed for a potential update?

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 31</u>:

a. The OHAG forecast is prepared annually. Generally, the steps in the OHAG forecasting process are as follows:

(1) Review of actual historical cost data.
(2) Identification of trends in actual data and review of potential known changes that could impact future OHAG expenses.
(3) Determination of whether the forecast should be updated, or if expected changes do not warrant a modification.
(4) If changes are deemed necessary, the appropriate modification is determined based on the driver of the change. For example, if the change is made due to a general upward trend in OHAG costs, the modified forecast will be updated to reflect this trend.

b. There is no particular number of historical years used as a basis in determining a cost trend for a given year. Idaho Power reviews actual historical data and determines the relevant review period based on known information and expectations of the future. For example, the 2014 update to the OHAG forecast (described below) was based on historical actual OHAG expenses for the years 2007 – 2013 because this time period captured the historical period during which deviations began to exist between actual and forecast OHAG expenses, which ultimately prompted the decision to update the forecast.

c. When the OHAG forecast is updated, a historical trend may be incorporated that takes into account total Idaho Power OHAG costs for all three coal plants. As previously discussed, due to the variance in OHAG expenses from year-to-year, when the need for a change is identified, the Company updates its OHAG forecast to reflect expectations on a going-forward basis. If a historical trend is expected to continue into the future, the Company will identify this historical trend and apply it to its future expectation of OHAG expenses. An example of a historical trend being applied to the forecast is discussed in the response to part e. below.

d. Since 2010, the OHAG forecast for the Jim Bridger and North Valmy plants has been updated once, in 2014. Pursuant to the Company's document retention policies, Idaho Power does not possess OHAG forecast data prior to 2010.

e. An update to the OHAG forecast for the Jim Bridger and North Valmy plants was prompted in 2014 due to variances in annual actual OHAG expenses and forecast OHAG expenses over several years. The tables below compare forecast OHAG expenses and actual OHAG expenses for the Jim Bridger and North Valmy plants for the years 2010 – 2013.

Jim Bridger	Actual IPC OHAG	Forecast IPC OHAG	Variance
2010	$4,099,423	$3,038,400	$1,061,023
2011	$3,899,558	$3,038,400	$861,158
2012	$3,689,978	$3,038,400	$651,578
2013	$3,692,961	$3,038,400	$654,561

North Valmy	Actual IPC OHAG	Forecast IPC OHAG	Variance
2010	$3,075,086	$2,874,000	$201,086
2011	$3,991,881	$2,874,000	$1,117,881
2012	$4,976,490	$2,874,000	$2,102,490
2013	$5,496,435	$2,874,000	$2,622,435

As the above tables show, forecasted OHAG had persistently underestimated the actual OHAG costs. Consistent with the upward OHAG cost trend in 2014, the North Valmy plant OHAG forecast was changed to $4,085,000 and the Jim Bridger plant OHAG forecast was changed to $3,538,400.

CASE: UE 314
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

January 31, 2017

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

A. My name is Lance Kaufman. I am a Senior Economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC or Commission). 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 summarize Staff's analysis and provide recommendations related to cost allocations and coal costs.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

- Staff/201, consisting of 1 page;
- Staff/202 [Idaho Power Company responses to selected Staff Data Requests (DRs)] consisting of 10 pages;
  - DRs 14 and 16 address cost allocations;
  - DRs 19, and 20 address Jim Bridger's fuel supply;
  - DR 22 addresses Bridger Coal Company's rate base;
  - DR 23 addresses Bridger Coal Company's depreciation expense; and
  - DR 24 and 25 address long term coal contract costs.
- Staff/203 (Allocation Example), consisting of 1 page.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, COST ALLOCATIONS

Q. Please summarize your conclusions regarding Idaho Power Company's allocations 2017 NVPC.

A. Staff concludes that Idaho Power Company (Idaho Power or Company) allocates costs in a method that does not accurately recover power cost expenses.

Q. How does Idaho Power allocate costs and design rates?

A. Idaho Power does not allocate total power costs. Instead, Idaho Power uses a rate update mechanism to allocate expenses incremental to the previous year. This mechanism is summarized in Staff/202, Kaufman/3.[1] Staff recaps the process in Staff/202 as follows:

First, total 2017 system power cost is estimated to be $382 million. Second, system load is estimated to be 14.6 million MWh. Third, dividing total cost by system load produces a cost per megawatt of $26.06. Fourth, the difference between the 2016 Annual Power Cost Update (APCU) cost per megawatt hour of $23.93 is subtracted from the 2017 APCU update cost per megawatt hour to arrive at an incremental cost of $2.13 per megawatt hour. Fifth, the Oregon jurisdictional "Incremental Net Power Cost Expense" (INPCE) is calculated by multiplying the forecasted 2017 Oregon load of 686,534 by the incremental cost per megawatt hour. Idaho Power estimates the Oregon INCPE to be $1,462,318.

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[1] See Staff/202, Kaufman/1 through Kaufman/3 (Idaho Power Responses to Staff DRs 14 and 16).

Idaho Power then calculates incremental rates to add to Oregon base rates to collect the INCPE. It is important to note that for Idaho Power, Oregon's base rates already include the 2016 power cost adjustments. So Idaho Power only calculates rate increase required to collect the incremental 2017 power cost expenses. The Oregon INCPE becomes an input into the Oregon rate spread and rate design mechanism presented by Idaho Power in Idaho Power/107, Blackwell/1.

Q. What is Staff's concern with Idaho Power's INPCE process?

A. The mechanism does not account for the fact that each service schedule has a different power cost rate and a different load growth rate. Depending on which service schedules are driving load growth, Idaho Power's methodology may over or under collect rates.

Q. Please provide an example of how this over or under collection could occur.

A. Staff/203 provides a simplified numeric example of how this over/under collection might happen. The allocation example shows rates over two different years (i.e. Year 1 and Year 2) and calculates rates under Idaho Power's INPCE method and under a Staff-proposed method which I refer to as the "total cost method."

Q. Please continue explaining your allocation example provided in Staff/203.

A. In the example, load grows from 100 to 110 MWh from Year 1 to Year 2. This load growth is driven by residential load. The cost per megawatt hour also increases by $1 from Year 1 to Year 2, so that total power costs increase $110 in Year 2. In the hypothetical scenario, the rates associated with Idaho Power's INPCE method over-collect power costs. This occurs because the rates charged to the growing residential customer class in Year 1 ($17.50) are higher than the combined rate in Year 1 ($15). Because residential rates are higher than the combined rate, when the residential class grows in Year 2, the old base rates from Year 1 will naturally collect a greater amount of power cost revenue. Even if rates are not updated, the Year 1 rates would collect a portion ($25) of the $110 INPCE.[2] In this example, the INPCE method over collects by $25[3] because the incremental rates are designed to collect exactly $110 and the growth of the higher priced customer class also collects an additional $25.

The specific impact of Idaho Power's methodology on the Company's 2017 APCU filing has not yet been ascertained because Staff does not have information regarding the amount of power costs already included in base rates. Staff will calculate the specific impact and update the Commission in Staff's Rebuttal Testimony.

Q. What is Staff's recommendation regarding the cost allocation issue?

A. Staff recommends that rather than using the Company's INPCE method, rates should be calculated using Staff's "total cost method."

Q. Please explain Staff's recommended total cost method.

A. The example for the total cost method is provided in lines 16 to 18 of Staff/203. Under this method, power costs would be separated from base rates and

[2] See Staff/203, Kaufman/1, Line 11.
[3] See Staff/203, Kaufman/1, Line 15.

recalculated each year. Rates would be calculated by allocating total power cost expense to service schedules rather than to incremental net power cost expense. Each year the old rate would be replaced by the new rate rather than updated by an incremental amount.

Q. Does Staff have an adjustment related to its "total cost method" recommendation?

A. No. This is because Staff's recommendation does not affect power costs. It affects the calculation of rates underlying net power costs. Idaho Power has not provided tariff sheets in conjunction with this filing because Idaho Power expects proposed rates to change. Should the Commission adopt Staff's total cost method approach, Idaho Power would then use it when the Company submits tariff sheets at the close of this docket.

ISSUE 2, COAL COSTS

Q. What issues related to coal costs did Staff investigate?

A. Staff investigated two issues: potential impact of minimum volume contracts and the prudence of the Jim Bridger facility coal costs.

Q. What did you find regarding minimum volume contracts?

A. Staff found that Idaho Power's 2017 Net Variable Power Cost (NVPC) forecast was not affected by minimum volume contracts.[4]

Q. What did you investigate regarding the Jim Bridger facility coal costs?

A. Staff investigated Idaho Power's oversight of Jim Bridger's fuel supply. Staff also investigated the related issue of the forecasted price for Bridger Coal Company (BCC) coal.

Q. What did you find regarding Idaho Power's oversite of Jim Bridger's fuel supply?

A. Between 2013 and 2015, Idaho Power did not analyze the appropriateness of purchasing coal from BCC.[5] In late 2016, Idaho Power evaluated four BCC life-of-mine scenarios.[6]

Q. Is it reasonable to expect Idaho Power to actively evaluate the ongoing fuel source for the Jim Bridger facility?

A. Yes, Idaho Power has the authority to choose the fuel source for the Jim Bridger facility.[7] In Order 13-132, the Commission stated "A minority owner who seeks to pass through to its ratepayers the costs of environmental

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[4] See Staff/202, Kaufman/9 and Kaufman/10 (Idaho Power Response to Staff DR 24 and 25).
[5] See Staff/202, Kaufman/5 and Kaufman/6 (Idaho Power Response to Staff DR 20).
[6] See Staff/202, Kaufman/5 and Kaufman/6 (Idaho Power Response to Staff DR 20).
[7] See Staff/202, Kaufman/4 (Idaho Power Response to Staff DR 19).

upgrades may not sign away its independent duty to review and carefully consider a majority owner's decision-making." In Order 13-132, the Commission was evaluating a $24.6 million pollution control investment at the Jim Bridger plant. Idaho Power's share of this investment was $8.2 million. Idaho Power's forecast for 2017 coal cost is approximately $60 million.[8] Given that Idaho Power's annual coal cost for Jim Bridger is six times greater than the disputed investment addressed by Order 13-132, the Commission's directive there should be applicable to fuel source as well as to environmental investments.

Q. What is your recommendation to the Commission regarding Idaho Power's oversight of the Jim Bridger facility's fuel supply?

A. Staff recommends the Commission affirm or clarify that minority owners of coal plants have a duty to review all major actions proposed or taken by the facility's majority owners, not only those related to environmental investments.

Q. What did you investigate regarding Bridger Coal Company coal costs?

A. Staff investigated the depreciation expense included in BCC coal costs. Idaho Power appears to be recovering depreciation costs for assets that are not included in base rates. Idaho Power incorporates capital costs for BCC through its general rate cases.[9] The most recent rate case was in filed in 2011 and docketed as UE 233. Idaho Power recovers depreciation expense for

[8] Idaho Power/101, Blackwell/1 shows Jim Bridger operating expense of $62 million. Coal cost is the primary component for this expense.
[9] See Staff/202, Kaufman/7 (Idaho Power Response to Staff DR 22).

BCC assets through the power cost mechanism.[10] The depreciation rates for these assets do not appear to be supported by a Commission-approved depreciation study. Idaho Power also does not appear to monitor the depreciation policy for BCC.[11]

Q. What do you recommend regarding Bridger Coal Company coal costs?

A. Staff recommends that depreciation costs associated with plant that is not currently in rate base be excluded from coal costs. Staff also recommends that the Commission direct Idaho Power to review the depreciation practices of its operating partner on an ongoing basis.

Q. Have you calculated a dollar value for your proposed treatment?

A. Staff does not have sufficient data at the time of writing this testimony to propose a specific dollar adjustment. Staff is seeking additional data through discovery requests. However, Staff does propose a specific and executable adjustment. To perform the adjustment, it is necessary to first tabulate the depreciation expense included in the BCC coal cost that is associated with plant added after Idaho Power's most recent rate case. Then, the depreciation expense is subtracted from 2017 BCC coal costs. Finally, BCC coal cost on a cost per ton basis is calculated and updates the Jim Bridger fuel cost input appropriately.

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[10] See Staff/202, Kaufman/8 (Idaho Power Response to Staff DR 23).
[11] In Staff/202, Kaufman/8 (Idaho Power Response to Staff DR 23) the Company states "Idaho Power is currently working with its operating partner to obtain a copy of the most recent depreciation analysis performed for BCC assets." This indicates that Idaho Power does not monitor depreciation practices for BCC.

Q. When will Staff propose its adjustment based upon these calculations?

A. Staff will provide a specific dollar value in rebuttal testimony.

Q. Did Idaho Power provide parties with a complete set of supporting workpapers in its initial filing?

A. Idaho Power did not provide workpapers with its initial power cost filing. Workpapers are an important component to evaluating net power costs because they allow parties to vet the assumptions and inputs used in the Company's model. Staff recommends that Idaho Power, Staff, and other parties work together to collaboratively update Idaho Power's filing requirements for future power cost cases.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UE 314
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

January 31, 2017

WITNESS QUALIFICATIONS STATEMENT

NAME:	Lance Kaufman
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 9730
EDUCATION:	In 2013 I received a Doctorate degree in economics from the University of Oregon. In 2008 I received a Master of Science degree in Economics from the University of Oregon. In 2004 I received a Bachelor of Business Administration in Economics from the University of Alaska Anchorage.
EXPERIENCE:	From March of 2013 to September of 2014 and from September of 2015 to the present I have been employed by the Oregon Public Utility Commission (OPUC). My current responsibilities include analysis of power costs, cost allocations, decoupling mechanisms, and sales forecasts. I have worked on power costs in the following OPUC dockets: IPC UE 301, IPC UE 305, PAC UE 307, and PGE UE 308. From September 2014 to September 2015 I was employed by Regulatory Affairs Public Advocacy group of the Alaska Department of Law. From 2008 to 2012 I was employed by the University of Oregon as an instructor. I taught undergraduate level courses in Microeconomics, Urban Economics, and Public Economics.

CASE: UE 314
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

January 31, 2017

IDAHO POWER®
An IDACORP Company

January 26, 2017

Subject: Docket No. UE 314 – 2017 Annual Power Cost Update ("APCU")
Idaho Power Company's ("Idaho Power" or "Company") **Redacted** Responses to the Public Utility Commission of Oregon ("Commission") Staff's Data Requests 14-25

STAFF'S DATA REQUEST NO. 14:

Please provide a complete explanation of how power costs are allocated or direct assigned to the Oregon jurisdiction.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 14:

Power costs are allocated to the Oregon jurisdiction by multiplying the system incremental per-unit cost by the forecasted Oregon jurisdictional loss-adjusted normalized sales for the test period.

The incremental per-unit cost between normalized net power supply expense ("NPSE") established in the 2016 APCU October Update and normalized NPSE proposed in the 2017 APCU October Update is $2.13 per megawatt-hour ("MWh"). The incremental cost per MWh is then multiplied by the forecasted Oregon jurisdictional loss-adjusted normalized sales of 686,534 MWh for the April 2017 to March 2018 test period. The resulting power supply costs of $1,462,318 are allocated to the Oregon jurisdiction.

<u>STAFF'S DATA REQUEST NO. 16</u>:

Please provide all workpapers used to calculate the 2017 Oregon allocation factors.

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 16</u>:

As discussed in the Company's response to Staff's Data Request No. 15, allocation factors were not used in determining Oregon jurisdictional power supply costs for the APCU.

Please see the attachment provided to illustrate the determination of Oregon-specific power supply costs for the APCU.

ATTACHMENT - RESPONSE TO STAFF'S DR 16

2017 APCU October Update
April 1, 2017 - March 31, 2018

Total Net Power Supply Expenses	$ 382,067,704
Forecast of System Loss-adjusted Normalized Sales (MWh)	14,661,439
Per-unit Cost ($/MWh)	$ 26.06
Per-unit Cost for 2016 APCU October Update ($/MWh)	$ 23.93
Incremental Per-Unit Cost ($/MWh)	**$ 2.13**
Incremental Net Power Supply Expenses	$ 31,228,866
Forecast of Oregon Jurisdictional Loss-adjusted Normalize Sales (MWh)	**686,534**
Oregon Jurisdictional Incremental Net Power Supply Expenses	**$ 1,462,318**
Forecast of Idaho Jurisdictional Loss-adjusted Normalize Sales (MWh)	13,974,905
Idaho Jurisdictional Incremental Net Power Supply Expenses	$ 29,766,548

STAFF'S DATA REQUEST NO. 19:

Does Idaho Power have authority to choose or influence the fuel source for Jim Bridger plant? If not, why not? Please provide any referenced documents or contracts. What is the review or control process between IPC and PacifiCorp with regard to fuel source decisions?

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

Yes. Idaho Power does have the authority to choose and influence the fuel source for the Jim Bridger plant ("Bridger Plant") with the goal of achieving the least-cost and lowest-risk fuel. Based on the forecast generation of the Bridger Plant, Idaho Power and PacifiCorp procure fuel volumes sufficient to meet generation needs. Fueling source decisions are reviewed and approved independently by each company.

STAFF'S DATA REQUEST NO. 20:

If Idaho Power has authority to choose or influence the fuel source for Jim Bridger plant, please provide all analysis performed by Idaho Power from 2013 to present regarding the appropriate fuel source for Jim Bridger plant.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 20:

As an engaged partner in the Bridger Plant and the Bridger Coal Company ("BCC") mine, Idaho Power continues to provide input, oversight, and review of these operations including the long-term fueling study as outlined in Order No. 16-482 from PacifiCorp's Transition Adjustment Mechanism filing.

In late 2016, Idaho Power independently performed analyses to evaluate the present value revenue requirement ("PVRR") impact of four BCC life of mine scenarios presented by the owner-operator. These analyses incorporated the cost of the BCC coal supply provided by the owner-operator, and third-party fuel supply needed for Idaho Power's required output of the Bridger Plant. Please see the protected information attachment providing the summary results and high level assumptions used in the directional analysis, along with the modeled PVRR detail.

[BEGIN PROTECTED INFORMATION]

[redacted]

[redacted]

[redacted]

[redacted]

[END PROTECTED INFORMATION]

These analyses will continue to be refined as options and assumptions change to identify the least cost, least risk fueling plan.

The response to this Request contains protected information and will be provided in accordance with the General Protective Order No. 16-505.

STAFF'S DATA REQUEST NO. 22:

Please explain how Idaho Power recovers the return on equity for Bridger Coal Company.

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

Idaho Power owns 100 percent of Idaho Energy Resources Company ("IERCo"), which has a one-third joint venture interest in BCC, a mine that supplies coal to the Bridger Plant. As a one-third owner in BCC, IERCo is entitled to one-third of the BCC net income and cash flows. Idaho Power accounts for IERCo as an equity method investment.

For general rate case revenue requirement determinations, Idaho Power includes its investment in IERCo as a component of utility rate base, and includes as an offset to the utility revenue requirement, the test-year IERCo earnings in the form of electric operating income. Coal delivered from BCC to the Bridger Plant is priced at the mine's cost plus an operating margin equal to the revenue requirement on IERCo rate base from the most recent general rate case. This pricing approach ensures that the Company does not earn more than its allowed return on its investment in IERCo between rate cases.

STAFF'S DATA REQUEST NO. 23:

Does Idaho Power include Bridger Coal Company depreciation expense in the 2017 Jim Bridger coal cost? If yes, please provide the most recent analysis used by Idaho Power to support the depreciable lives, salvage value, and cost of removal for Bridger Coal Company depreciable assets.

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

Yes. Idaho Power considers all projected operating costs for BCC, including depreciation expense, in the 2017 delivered Bridger Plant coal cost forecast. Idaho Power, through its subsidiary IERCO, is a 33 percent owner of BCC. IERCO is accounted for under the equity method, and is not consolidated. As such, all fixed asset records and analyses to support useful lives, salvage values, etc. at BCC are maintained by the operating partner, PacifiCorp. Please see the attachment to the Company's response to Staff's Data Request No. 21 for the most recent depreciation schedule for BCC assets. Idaho Power is currently working with its operating partner to obtain a copy of the most recent depreciation analysis performed for BCC assets, and will provide Staff with an updated response as soon as possible.

STAFF'S DATA REQUEST NO. 24:

Does Idaho Power expect to incur any contract penalties associated with contract minimum volumes? If yes, please identify all such contracts.

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

No. Idaho Power does not expect to incur any penalties associated with contract minimum volumes at any of its coal-fired power plants.

STAFF'S DATA REQUEST NO. 25:

Does Idaho Power expect to modify plant dispatch in order to accommodate contract minimum volumes? If yes, please identify all such contracts and describe how Idaho Power models or accounts for minimum volumes in the Company's 2017 APCU.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 25:

No. Idaho Power does not expect to modify plant dispatch to accommodate minimum volumes.

CASE: UE 314
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 203

Exhibits in Support
Of Opening Testimony

January 31, 2017

Allocation Example

Line		(a) Total	(b) Forecasted MWh	(c) Cost per MWh	(d)	(e)	(f)
1	Year 1 power cost	$1,500	100	$15			
2	Year 2 power cost	$1,760	110	$16			
3	Year 2 increase	$260	10	$1			
4	Year 2 Revenue at Year 1 Rate			$1,650			
5	Incremental Expense			$110			

Year 1 Rate Design

Line		Rate Case Allocator	Share of total cost	Load		Total Charge	Revenue
6	Residential	0.7	$1,050	60		$17.50	$1,050
7	Industrial	0.3	$450	40		$11.25	$450

Year 2 at Year 1 Rates

Line				Load		Total Charge	Revenue
8	Residential			70		$17.50	$1,225
9	Industrial			40		$11.25	$450
10	Total						$1,675
11	line 9 minus line 2 column a			**Incremental Revenue**			$25

Year 2 Idaho Power Method

Line		Rate Case Allocator	Share of incremental cost	Load	Incremental Charge	Total Charge	Revenue
12	Residential	0.7	$77	70	$1.10	$18.60	$1,302
13	Industrial	0.3	$33	40	$0.83	$12.08	$483
14	Total		$110				$1,785
15	line 9 minus line 2 column a				**Overcollection**		$25

Year 2 Staff Method

Line		Rate Case Allocator	Share of total cost	Load		Total Charge	Revenue
16	Residential	0.7	$1,232	70		$17.60	$1,232
17	Industrial	0.3	$528	40		$13.20	$528
18	Total		$1,760				$1,760

CASE: UE 314
WITNESS: DEBORAH GLOSSER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

January 31, 2017

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

A. My name is Deborah Glosser. I am a Sr. Utility Analyst employed in the Energy Resources and Planning 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. The purpose of my testimony is to give my expert opinion on Idaho Power Gas Company's (Idaho Power or Company) natural gas pricing forecast strategy as described in Company's responses to Staff DRs Nos. 1-4.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/301 (Witness Qualification Statement), consisting of 1 page, and Exhibit/302 (Company DR Responses), consisting of 4 pages.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, NATURAL GAS PRICING FORECAST NORMALIZATION – ARITHMETIC MEAN

Q. Idaho Power has used the arithmetic mean of the NYMEX, EIA, and Moody's forecasts to compute a normalized gas price for the 2017 APCU. Is the arithmetic mean an appropriate metric for normalizing gas prices?

A. Idaho Power initially stated that it selected the median natural gas price on line 8 of Idaho Power/100, Blackwell/10 of the present docket. A replacement page was filed with the Commission on January 5, 2017 to correct the error and clarify that the arithmetic mean was used.

As to the specific question, yes, I believe the arithmetic mean of the three pricing forecasts is an appropriate metric for normalizing natural gas prices for APCU purposes. The Commission has previously accepted the use of the arithmetic mean to reduce the impact of volatility in short term market prices. Indeed, the Commission accepted the mean value method in Idaho Power's previous eight APCU dockets, most recently in May 2016 in Order No. 16-206.

Q. Please explain how the arithmetic mean is calculated and describe how it compares to other methods for computing a normalized gas price.

A. The arithmetic mean is calculated by summing the three forecasts and dividing by the total number of forecasts used – here, three. The arithmetic mean as used by the Company is superior to either a mode or median pricing index value for normalizing the impact of volatility in short term market prices. The use of the mode of the three forecasts is not possible because each index produces a unique price. The use of a median value is not a commonly used metric for normally distributed datasets, as it is more suitable for a skewed distribution and deriving central tendencies of a dataset. Pricing forecasts such as the natural gas price indices should tend towards a normal distribution – particularly when there are only three inputs.

ISSUE 2, NATURAL GAS PRICING FORCECAST – PRICING INDICES

Q. How has Idaho Power changed its computation of the natural gas price forecast?

A. Idaho Power previously used five pricing forecasts to drive the calculation of its natural gas price estimation. The Company has now switched to utilizing only three: the NYMEX Henry Hub, EIA, and Moody's forecast. It no longer uses the Wood Mackenzie or IHS services.

Q. Would there be any benefit to using all five indices for the natural gas pricing forecast?

A. No. In this case, the use of the three pricing forecast standards by the Company is appropriate. When all five pricing indices are used in the model, a forecast natural gas price of $3.07 per MMBtu is produced, as opposed to $3.06 MMBtu forecasted when using the three indices. The $0.01 pricing forecast difference is "noise" in the data and there would not be any benefit for the Company to use all five pricing forecasts. A forecast difference of $0.01 would not propagate considerable pricing differences over time. Pricing curves are more sensitive to the effective starting date of the forecast than they are to differences in the initial values of this magnitude. The inclusion of the two additional indices for this year's APCU would not substantially alter or improve the forecast, given the triviality of the difference in initial values between the three and five price forecast models.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UE 314
WITNESS: DEBORAH GLOSSER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

January 31, 2017

WITNESS QUALIFICATION STATEMENT

NAME:	Deborah Glosser
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Sr. Utility Analyst Energy Resources and Planning
ADDRESS:	201 High St. SE Ste. 100 Salem, OR 97301-3612
EDUCATION:	Bachelor of Arts, Computational Linguistics, The Ohio State University Juris Doctorate, Law, Duquesne University Master of Science, Geophysics, University of Pittsburgh
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission (Commission) since October of 2016. My responsibilities include providing engineering and model analysis for filings made by electric utilities, related to their system operations and resource procurement and planning. Prior to working for the Commission I was a research geophysicist fellow at the United States Department of Energy. There, I developed physical and statistical models related to fossil energy resources. I published several peer review and technical papers related to energy exploration. I also served as a technical expert on a national laboratory task force, where we were tasked with developing science based recommendations to inform the improvement of federal regulation of underground natural gas storage well safety. Prior to my work at US DOE, I worked as an attorney in private industry.

CASE: UE 314
WITNESS: DEBORAH GLOSSER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

January 31, 2017

January 6, 2017

Subject: Docket No. UE 314 – 2017 Annual Power Cost Update ("APCU")
Idaho Power Company's Responses to the Public Utility Commission of Oregon Staff's Data Request Nos. 1-4

STAFF'S DATA REQUEST NO. 1:

Please describe why the median natural gas price was selected for the pricing forecast. How is using the median natural gas price as opposed to other metrics expected to normalize the gas price?

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 1:

The median natural gas price was not selected for the pricing forecast. The statement made on Idaho Power/100, Blackwell/10, line 8 is incorrect and a replacement page was filed with the Public Utility Commission of Oregon on January 5, 2017.

For the 2017 APCU, New York Mercantile Exchange ("NYMEX"), U.S. Energy Information Administration ("EIA"), and Moody's Corporation forecast data were included in the methodology and the arithmetic mean was calculated to determine a normalized gas price of $3.06 per MMBtu. The normalization process reduces the impact of volatility that may occur in the short term gas market. The Commission has accepted use of the arithmetic mean to determine a normalized gas price in Idaho Power's previous eight APCU dockets, most recently in May 2016 in Order No. 16-206.

STAFF'S DATA REQUEST NO. 2:

How do your natural gas price models change when the following values are chosen

a. Arithmetic mean; and
b. Mode

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 2:

a. As described in Idaho Power Company's ("Idaho Power" or "Company") response to Staff's Data Request No. 1, the natural gas price model used the arithmetic mean to determine a normalized gas price of $3.06 per MMBtu for the 2017 APCU.

b. The natural gas price model will not produce a forecast natural gas price using the mode. The natural gas price model uses NYMEX, EIA, and Moody's Corporation forecast data to determine a forecast natural gas price. As each of these indices produce a different natural gas price, and none of the values occur more than once, the natural gas price model will not produce a forecast natural gas price using the mode.

STAFF'S DATA REQUEST NO. 3:

Are there other industry pricing forecast standards (such as different combinations or weights of pricing indices) that could be used for computing natural gas pricing? If yes, please specify these other standards.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 3:

For natural gas price forecasting purposes, the Company uses publicly available information from the NYMEX Henry Hub natural gas futures contract and EIA. Idaho Power also uses paid services provided by Moody's Corporation. Similar to Moody's Corporation, S&P Global Platts, Wood Mackenzie, and IHS Cambridge Energy Research Associates offer paid subscriptions to provide natural gas price forecasts. However, Idaho Power does not currently subscribe to these services.

STAFF'S DATA REQUEST NO. 4:

How does your model change when all five pricing indices are used, as opposed to the three selected?

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 4:

When all five pricing indices are used in the model, a forecast natural gas price of $3.07 per MMBtu is produced.