Davison Van Cleve PC
Attorneys at Law
TEL (503) 241-7242 ● FAX (503) 241-8160 ● jog@dvclaw.com
Suite 400
333 SW Taylor
Portland, OR 97204

June 29, 2015

Via Electronic Filing & Federal Express

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE
Salem OR 97301-3612

Re: In the Matter of PACIFICORP, dba PACIFIC POWER
2016 Transition Adjustment Mechanism
Docket No. UE 296

Dear Filing Center:

Enclosed for filing in the above-referenced docket, please find the Opening Testimony and Exhibits of Bradley G. Mullins on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Pursuant to Protective Order No. 10-069, the sealed confidential portions of Mr. Mullins' testimony and exhibits will follow to the Commission via Federal Express and to the parties that have signed the protective order via First Class U.S. Mail.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the confidential portions of the **Opening Testimony and Exhibits of ICNU** upon the parties shown below by sending copies via First Class U.S. Mail, postage prepaid.

Dated at Portland, Oregon, this 29th day of June, 2015.

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

CITIZENS' UTILITY BOARD OF OREGON
ROBERT JENKS
SOMMER TEMPLET
610 SW BROADWAY, STE 400
PORTLAND OR 97205
bob@oregoncub.org
sommer@oregoncub.org

PUC STAFF – DEPARTMENT OF JUSTICE
MICHAEL T. WEIRICH
BUSINESS ACTIVITIES SECTION
1162 COURT ST NE
SALEM, OR 97301-4796
michael.weirich@state.or.us

PACIFICORP
ETTA LOCKEY
SENIOR COUNSEL
825 NE MULTNOMAH ST.,
SUITE 1800
PORTLAND, OR 97232
etta.lockey@pacificorp.com

PUBLIC UTILITY COMMISSION OF OREGON
JORGE ORDONEZ
P.O. BOX 1088
SALEM, OR 97308-1088
jorge.ordonez@state.or.us

ENERGY STRATEGIES LLC
KEVIN HIGGINS
215 STATE ST – STE 200
SALT LAKE CITY, UT 84111-2322
khiggins@energystrat.com

MCDOWELL RACKNER & GIBSON PC
KATHERINE A. MCDOWELL
419 SW 11TH AVE., SUITE 400
PORTLAND OR 97205
katherine@mcd-law.com

RICHARDSON ADAMS, PLLC
GREGORY M. ADAMS
PO BOX 7218
BOISE ID 83702
greg@richardsonadams.com

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 296

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
2016 Transition Adjustment Mechanism.	)
	)
____	)

REDACTED OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

June 29, 2015

TABLE OF CONTENTS TO THE REDACTED OPENING TESTIMONY OF BRADLEY G. MULLINS

EXHIBIT LIST

Exhibit ICNU/101—Qualification Statement of Bradley G. Mullins

Confidential Exhibit ICNU/102—Excerpts of February 13, 2015 Semi-Annual Hedging Report

Confidential Exhibit ICNU/103—Responses to ICNU Data Requests

Confidential Exhibit ICNU/104— Calculation of EIM Inter-regional Dispatch Shape

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is 333 SW Taylor Street, Suite 400, Portland, Oregon 97204.

Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an independent consultant representing industrial customers throughout the western United States. I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including PacifiCorp (or the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. A summary of my education and work experience can be found at ICNU/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses the Company's Transition Adjustment Mechanism ("TAM") filing for 2016. Specifically, my testimony discusses the Company's request for an $11.8 million or 0.9% rate increase for Oregon ratepayers in connection with its $1,537.5 million total-Company net power cost ("NPC") forecast developed using the Generation and Regulation Initiative Decision Tools ("GRID") model.[1/] The Company's proposed level of NPC represents a $64.8 million total-Company increase relative to the NPC approved in the Company's 2015 TAM.[2/] My testimony discusses several specific adjustments and corrections

---

[1/] PAC/100 at 3:8-14. Note that all figures are drawn from the Company's initial filing. While the Company distributed a list of corrections and omissions to parties on June 8, 2015, stating a total increase of approximately $1 million to filed NPC, a full update is not expected from the Company until August 3, 2015.

[2/] Id.

to the Company's GRID modeling, as well as policy issues surrounding the Company's overall level of NPC.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The following is a summary of my testimony, which is organized respectively:

(1) **System Balancing Adjustment:** The Company has proposed a complex series of adjustments to reflect what it claims to be additional costs associated with its trading activities in forward markets. I generally disagree with the concepts and calculations behind the proposed adjustments and recommend that the Commission reject the Company's proposal. In connection with the Company's proposal, I also make an alternative proposal to model market liquidity in GRID using a bid-ask spread. The net impact of these recommendations will reduce NPC by $38.2 million on a total-Company basis, with $9.4 million allocated to Oregon.

(2) **Reserves:**

(a) Regulation Reserve Correction. The Company's modeling of reserves contains an error. Reserve contracts that provide only load following reserve services have incorrectly been applied as an offset to regulation reserves. I propose to correct this error, increasing NPC by $2.6 million on a total-Company basis, with $0.7 million allocated to Oregon.

(b) Reliability Metric. The reserves in the Company's GRID model are calculated based on a 99.7% confidence interval. However, the Company's actual historical reliability performance has been measured at lower levels based on Control Performance Standard 2. Accordingly, I recommend modeling a 90% confidence interval, which will reduce NPC by $11.2 million on a total-Company basis, with $2.8 million allocated to Oregon.

(c) PSE & APS Reserve Diversity. While the Company included flexibility reserve diversity benefits associated with the addition of NV Energy into the Energy Imbalance Market ("EIM"), it did not include incremental flexibility reserve savings associated with the entrance of Puget Sound Energy ("PSE") and Arizona Public Service Company ("APS"). I propose to incorporate this additional reserve savings into the GRID model, reducing NPC by $60,750 on a total-Company basis, with $15,020 allocated to Oregon.

(d) Idaho Power Asset Exchange. The Company will gain additional dynamic capacity between balancing areas as a result of the Idaho Power Asset Exchange. However, the Company has not modeled this additional capacity and has restricted the ability of GRID to perform dynamic transfers between balancing areas. I propose a methodology that will properly model dynamic capacity between balancing areas, reducing NPC by $1.3 million on a total-Company basis, with $0.3 million allocated to Oregon.

(3) **Inter-regional EIM Dispatch Benefits:**

(a) Seasonality. The Company calculated the level of inter-regional EIM benefits in the test period using only two months of data—December 2014 and January 2015. The economic margins used in these two winter months, however, are not representative of the margins expected to be earned in the summer months. Accordingly, I propose a methodology to tie the forecasted economic margins of EIM transfers with the Cal-ISO to the seasonal spreads between the Mid-Columbia and California-Oregon Border Markets, reducing NPC by $1.5 million on a total-Company basis, with $0.4 million allocated to Oregon.

(b) New EIM Participants. The Company excluded a provision to account for additional inter-regional EIM transfers with new participants, including NV Energy, PSE and APS. I propose a methodology to account for these additional inter-regional EIM transfers that will reduce NPC by $3.2 million on a total-Company basis, with $0.8 million allocated to Oregon.

(4) **Hermiston Purchase Expiration:**

(a) Prudence. The Company's analysis of whether to extend the Hermiston Purchase contract demonstrates a fundamental flaw in the Company's Integrated Resource Plan ("IRP"). I recommend that the Commission make a finding that the Company's analysis of the Hermiston Purchase contract was not prudent because the Company did not evaluate the benefits of the contract on the winter peak.

(b) Point-to-Point Transmission. The Company includes in NPC transmission costs necessary to deliver the full output of the Hermiston facility onto its system. A portion of these costs will no longer be used and useful when the Hermiston Purchase contract expires. I propose to remove from NPC the unused portion of the Hermiston point-to-point transmission contract, resulting in a $0.2 million reduction to NPC on a total-Company basis, with $54,336 allocated to Oregon.

(5) **Outage Modeling:** The Company's new methodology to develop a schedule of forced outages in GRID results in a pattern of frequent, short outages that is not representative of actual operations. Accordingly, I recommend that the Company continue to use the methodology approved in Docket No. UM 1355, reducing NPC by $0.8 million on a total-Company basis, with $0.2 million allocated to Oregon.

(6) **Wind Profiles:**

(a) Avian Protection. The Company has proposed to reduce the output from several Wyoming wind resources to account for avian protection curtailments. This adjustment is immaterial and will not improve the accuracy of the Company's overall wind forecasts. I propose to remove this adjustment, reducing NPC by $0.2 million on a total-Company basis, with $52,107 allocated to Oregon.

(b) Rolling Averages. The Company proposes to model output from wind power purchase agreements ("PPAs") using a four-year rolling average. Four years is too short a time period to properly normalize output from wind facilities. I propose to remove this adjustment, reducing NPC by $5.8 million on a total-Company basis, with $1.4 million allocated to Oregon.

Q. HAVE YOU PREPARED A SUMMARY TABLE TO DETAIL THE IMPACT OF EACH OF THESE RECOMMENDATIONS?

A. Table 1, below, details the impact of each of these recommendations relative to the NPC in the Company's initial filing.

TABLE 1
Summary of Recommended NPC

	$000 Total-Company	Oregon-Allocated
2015 TAM	1,472,643	363,705
Company Filing	1,537,484	374,516
NPC Increase	64,842	10,811
Other Revenue Adjustment	8,803	2,296
EIM Costs Reduction	(2,088)	(547)
Load Adjustment	-	(808)
Company Proposed Rate Increase	**71,557**	**11,752**
Recommended Adjustments:		
1a Reject System Balancing Adj.	(31,300)	(7,739)
1b Market Liquidity Proposal	(6,862)	(1,697)
2a Reserves - Regulation Correction	2,633	651
2b Reserves - Reliability Metric	(11,240)	(2,779)
2c Reserves - PSE & APS Reserve Diversity	(61)	(15)
2d Reserves - Idaho Power Asset Exchange	(1,327)	(328)
3a EIM Disp. Benefit - Seasonality	(1,471)	(364)
3b EIM Disp. Benefit - New Participants	(3,158)	(781)
4b Hermiston - PTP Contract	(220)	(54)
5 Outage Modeling	(789)	(195)
6a Wind Profile - Avian Protection	(211)	(52)
6b Wind Profile - Rolling Average	(5,758)	(1,424)
Total Adjustments	(59,763)	(14,776)
Recommended Rate Increase (Decrease)	**11,794**	**(3,024)**

Q. TO THE EXTENT YOUR OPENING TESTIMONY DOES NOT ADDRESS A PARTICULAR ISSUE, SHOULD THAT BE INTERPRETED AS YOUR ACCEPTANCE OF THAT ISSUE?

A. No.

II. SYSTEM BALANCING ADJUSTMENT

Q. WHAT IS YOUR RECOMMENDATION RELATED TO SYSTEM BALANCING?

A. The Company has proposed a complex series of adjustments in the GRID model, which it suggests are justified on the basis of reflecting alleged system balancing costs—i.e., the costs associated with transacting in forward markets. Collectively, the adjustments proposed by the

Company would result in a $31.3 million increase to the total-Company NPC forecast, with approximately $8.0 million allocated to Oregon.[3/]

Following my review of the Company's analysis, I disagree that the Company's balancing activities in forward and day-ahead markets warrant extraneous adjustments to its power cost forecast. I also disagree with the calculations performed by the Company to develop these adjustments, as they have no sound basis to be used to develop a power cost forecast. Accordingly, I recommend that the Commission reject the system balancing modeling adjustments proposed by the Company.

In order to address an ancillary aspect of the Company's proposal, however, I propose an alternative modeling change. I believe that there is merit in using bid-ask spreads for the purpose of modeling market liquidity in GRID. Accordingly, I propose the use of realistic bid-ask spreads in GRID as a replacement for the present market cap liquidity constraint. Collectively, the net impact of removing the Company's proposal and adopting my alternative recommendation will reduce NPC relative to the Company's initial filing by $38.2 million on a total-Company basis, with $9.4 million allocated to Oregon.

a. System Balancing, Generally

Q. WHY DOES THE COMPANY SUGGEST THAT A MODELING CHANGE IS REQUIRED TO REFLECT THE COST OF BALANCING IN FORWARD MARKETS?

A. The Company claims that the GRID model does not properly reflect the cost to the Company of balancing its system in forward markets, including both term (i.e., monthly) and day-ahead markets.[4/] The Company alleges that as a result of its participation in these forward markets,

3/ Id. at 30:4-8.
4/ Id. at 22:19-30:17.

the GRID model does not properly reflect the total volume of transactions or the price for which the Company ultimately pays to transact power.[5/]

Q. WHAT IS THE NATURE OF THE COMPANY'S TRADING ACTIVITIES IN FORWARD AND SPOT MARKETS?

A. The Company's participation in forward markets is tied largely into its overall hedging strategy. [redacted].[7/] Because the Company is the owner of one of the largest generation portfolios in the West, the Company's primary hedging position in natural gas markets [redacted].[8/] In terms of power, the Company's primary hedging position [redacted].[9/]

Q. WHY ARE THE COMPANY'S HEDGING PRACTICES RELEVANT TO THE COMPANY'S ADJUSTMENT PROPOSAL?

A. For purposes of the Company's system balancing proposal, the alleged system balancing costs in question are actually concerned with hedging contracts. It has generally been suggested by the Company that there are no systematic costs or biases associated with its hedging

---

5/ PAC/100 at 22:20-23:4
6/ Confidential ICNU/102 at 1 ([redacted]).
7/ Id. at 1-4.
8/ Id. at 5.
9/ Id.

practices.[10/] If the Commission were to conclude in this proceeding that there are, in fact, systematic costs or biases associated with entering into forward hedging transactions, there would be a reason to rethink the prudence of the Company's entire hedging policy, as well as the equity of passing those hedging costs onto customers.

Q. DOES IT MAKE A DIFFERENCE THAT THE TRANSACTIONS IN QUESTION ARE PRIMARILY SALES TRANSACTIONS?

A. Yes. In the Company's February 13, 2015 Semi-Annual Hedging Report, the volume of physical forward power sales exceeded the volume of sales purchase transactions by a factor of approximately two-to-one.[11/] Thus, the alleged systematic costs associated with these forward transactions are not tied intrinsically to load service. Rather, they are tied to the overall optimization of the Company's system operations, including marketing the output from its generation fleet.

Q. WHAT ARE THE DISCRETE ADJUSTMENTS THAT THE COMPANY HAS PROPOSED?

A. The Company argues that it is justified in making two discrete adjustments to NPC. First, the Company proposes an extraneous, out-of-model adjustment to NPC in the amount of $14.5 million.[12/] For purposes of this first adjustment, the Company also manually forces an additional 2,594 GWh of sales and 2,594 GWh of offsetting purchase transactions in the NPC results table.[13/] Second, the Company incorporated into the hourly market prices used by the GRID model a bid-ask spread, which according to my calculations is $7.25/MWh on average.

10/ E.g., In re Application of Rocky Mountain Power for Approval of Its Proposed Energy Cost Adjustment Mechanism, Utah Public Service Commission Docket No. 09-035-15, Suppl. Direct Testimony of Frank C. Graves at 40:799-800, and Rebuttal Testimony of Frank C. Graves at 28:462-67, 33:575-85; In re PacifiCorp, dba Pacific Power, 2012 Transition Adjustment Mechanism, Docket No. UE 227, PPL/105, Duvall/8:5-6, and PPL/400, Bird/4-5, 13, 16.

11/ Confidential ICNU/102 at 5.

12/ PAC/100 at 29:12-19.

13/ Id.

This second adjustment results in a $16.8 million reduction to NPC on a total-Company basis.[14]

While the merits of both of these adjustments will be discussed in depth below, I am unable to understand the relationship of these calculations to what the Company claims to be the underlying problem—that there is a systematic cost associated with making transactions in forward and day-ahead markets. For example, modeling a bid-ask spread that is on average 24.2% of the ultimate market price is, in addition to being excessive, not a cost associated with entering into forward transactions. Rather, a bid-ask spread is a measurement of market liquidity.

Further, what the Company claims to be the underlying modeling problem is generally recognized by other utilities not to be an deficiency in power cost modeling, as it is generally recognized that there is no systematic bias between forward market prices and spot market prices.

Q. ARE YOU AWARE OF ANY OTHER UTILITY THAT USES THESE MODELING ADJUSTMENTS TO CALCULATE NET POWER COSTS?

A. No. I have reviewed the power cost modeling of the majority of investor-owned utilities located in the Northwest, including Portland General Electric Company, Puget Sound Energy, Avista Corporation, and the Bonneville Power Administration. Each of these utilities participates in the same forward and day-ahead markets as the Company. Yet, none has alleged that there is a systematic cost of system balancing not already reflected in their respective power cost models—let alone proposed the extraneous modeling adjustments that the Company has proposed in this proceeding. For these utilities, the costs associated with

[14] Id. at 29:4-11

balancing transactions are typically addressed through a day-ahead system balancing charge, an adjustment that the Company has already made to its power cost forecast.

Q. WHY IS IT GENERALLY ACCEPTED BY OTHER UTILITIES THAT THERE IS NO SYSTEMATIC COST ASSOCIATED WITH SYSTEM BALANCING?

A. For purposes of power cost forecasting, it is generally accepted that there is no systematic bias between forward market prices and spot market prices. Accordingly, the market prices at which a utility will transact in forward markets to balance its systems represent the median expectation of what the ultimate spot market prices will be. The notion that forward prices are an unbiased estimate for future spot prices, however, does not mean that the future spot market price will ultimately be equal to what the forward market predicts. Rather, the price at which a utility may enter into a transaction in forward markets is expected to be higher than spot prices 50% of the time, and less than spot prices the other 50% of the time. Thus, to the extent that a utility is ultimately required to transact for more or less power in hourly spot markets than previously sold or purchased in forward markets, it is expected to be no better or worse off than if it had solely purchased its power requirements in spot markets.

Q. HOW DOES THIS CONCEPT RELATE TO POWER COST MODELING?

A. This concept is central to power cost forecasting, which is nothing more than a calculation of system dispatch based upon current forward market prices for gas and electricity. One of the reasons why a power forecast based on forward prices can be used in ratemaking, rather than being pure speculation on the part of the utility, is because there is an expectation that the forward prices used in the calculation are an unbiased predictor of future spot prices. If this concept is abandoned and utilities are given unfettered discretion surrounding the imposition of adjustments to forward market prices, then the basic construct underlying the use of power cost forecasting for ratemaking purposes begins to unravel, leading to a conclusion that a power cost forecast may no longer meet the standard to be used for ratemaking.

Q. WHY DO FORWARD PRICES REPRESENT AN UNBIASED FORECAST OF SPOT PRICES?

A. The principle that forward prices represent an unbiased estimate of future spot prices has its origin in arbitrage pricing theory. In an efficient market there are assumed to be no arbitrage opportunities—i.e., there is no opportunity for a market participant to earn a risk-free profit. To the extent that risk-free opportunities for profit were to exist in a forward market, the mechanics of supply and demand would result in an adjustment to prices to eliminate the opportunity for a risk-free return. Accordingly, arbitrage pricing theory is commonly used in the field of financial engineering to develop pricing for derivative contracts, including forward contracts, by determining the price at which no arbitrage opportunities exist.

Q. HOW DOES ARBITRAGE PRICING THEORY ELIMINATE BIAS BETWEEN FORWARD AND SPOT PRICES?

A. For the purposes of forward contracts, including those in question in the Company's adjustment, if there were a systematic bias between forward and spot market power prices, a market participant would have an opportunity to receive arbitrage profits by purchasing in the forward market and selling in the spot market, or vice versa.

Q. HOW DOES THIS RELATE TO THE COMPANY'S PROPOSAL?

A. It is self-evident that the Company will not be able to perfectly hedge or balance its position in forward markets. Provided that there is no change in market price between the forward period and prompt periods, however, there should be no additional cost associated with the Company's imperfect position. What it appears that the Company has attempted to do in its proposal is to incorporate the losses that it has historically experienced as a result of changes in market prices between the forward period and the prompt period. In other words, the Company's proposals would result in including historical gains or losses from forward contracts in rates, a result that I disagree with.

b. Out-of-Model Adjustment

Q. WHAT WAS THE FIRST COMPONENT OF THE COMPANY'S ADJUSTMENT PROPOSAL?

A. The first aspect of the Company's proposal is an out-of-model adjustment that the Company alleges accounts for the costs of making monthly transactions in forward markets. For purposes of this adjustment, the Company made an extraneous adjustment outside of the GRID model, increasing NPC by $14.5 million on a total-Company basis. The Company also added outside of the GRID model 2,594 GWh of additional sales and 2,594 GWh of additional purchases into the final NPC report template. These additional sales and purchases are offsetting and have no effect on NPC.

Q. WHY DID THE COMPANY PERFORM THIS ADJUSTMENT?

A. It is not entirely clear. The Company alleged that the GRID model under-forecasts the level of sales and purchases relative to the amount made in actual operations, including forward hedging contracts.[15/] This is a perplexing argument, particularly since the Company has argued in recent years that the exact opposite is true—that the GRID model over forecasts sales and purchases. For example, in Docket No. UE 245, Mr. Duvall performed a comparison between GRID modeled sales volumes and actual sales volumes over the period 2007 through 2011 in order to justify the continued use of the market cap assumption in the GRID model.[16/] In that analysis, he demonstrated that "GRID over forecasts wholesale power sales in every year" and

15/ Id. at 29:12-19.
16/ See In re PacifiCorp, dba Pacific Power, 2013 Transition Adjustment Mechanism, Docket No. UE 245, PAC/100 at 17:17-22:22.

that "[r]emoving market caps would cause GRID to further over forecast wholesale power sales."[17/]

Q. DO YOU AGREE WITH THE COMPANY THAT GRID PRODUCES ARTIFICIALLY LOW SALES AND PURCHASE VOLUMES?

A. No. First, the historical data does not support the Company's claim that sales and purchase volumes are being systematically under forecast in the GRID model. Second, the sales volumes in GRID are already being artificially constrained due to the application of market caps. To the extent that there is a finding that sales and purchase volumes are too low, that would be a reason to eliminate the market cap constraint in the GRID model, not a reason to add an arbitrary amount of offsetting sales and purchases outside of the GRID model.

Q. HAVE YOU PERFORMED A COMPARISON BETWEEN HISTORICAL SALES AND PURCHASES TO THE LEVEL PROPOSED BY THE COMPANY?

A. Yes. Confidential Figure 1, below, compares the historical level of sales and purchases to the amounts proposed by the Company in this proceeding, including the impact of the offsetting sales and purchases included outside of the GRID model.

CONFIDENTIAL FIGURE 1

Actual Sales and Purchases Compared to the Company Proposal

[redacted]

[17/] Id. at 20:16-18

Confidential Figure 1 details the level of sales and purchases actually made over the historical period 2010 through 2014. The historical data is from the Company's actual net power cost reports used for regulatory reporting purposes. The historical data is compared to the level of sales and purchases included in the Company's filed GRID NPC report, including the additional out-of-model sales and purchases proposed by the Company. As demonstrated and in conflict with the Company's argument, the Company's proposal would result in a level of sales and purchases that do not correspond to the levels of transactions historically made.

Q. WHAT IS YOUR UNDERSTANDING OF WHAT THE COMPANY DID?

A. My understanding is that the Company estimated a quantity of offsetting forward hedging transactions that it expected to be made in the test period. In this case, the Company assumed that there would be an additional 2,594 GWh of equal and offsetting forward sales and forward purchase transactions. It then assigned prices to the forward purchase transactions that were higher than the prices assigned to forward sales transactions. The Company suggests that this price spread is supported by historical data.[18/] In this case, the average sales price was $30.11/MWH and the average purchase price was $35.71 MWh, resulting in a spread between the offsetting sales and purchases of $5.60/MWh. Thus, to arrive at its adjustment, the Company effectively multiplied the 2,594 GWh figure by the $5.60/MWh average spread in the NPC report spreadsheet to arrive at a $14.5 million reduction to NPC. These values can be derived from the face of Company's NPC report, where the Company forecast $78.1 million in sales[19/] and $92.7 million in purchases[20/] under the category DA-RT Balancing. The average

---

[18/] PAC/100 at 30:1-3.
[19/] PAC/102 at 1.
[20/] Id. at 4.

price of these transactions can be derived by dividing the dollar figures by the 2,594 GWh of offsetting sales and purchases transactions proposed by the Company.

Q. WHAT IS WRONG WITH THIS PROPOSAL?

A. In addition to the notion that it assumes there will be systematic losses associated with forward hedging contracts, which is addressed above, there are several problems with the mechanics of this proposal. First, the hedging transactions performed by the Company in actual operations are not equal and offsetting. Based on the Company's February 13, 2015 Semi-Annual Hedging Report, the Company enters into approximately twice the volume of forward hedging contracts for sales as it does for purchases.

Q. HOW WOULD THE COMPANY'S ADJUSTMENT CHANGE IF IT USED THE HISTORICAL RELATIONSHIP BETWEEN SALES AND PURCHASES?

A. If the historical relationship between sales and purchase transactions was incorporated into this adjustment, the Company's adjustment would produce a reduction to NPC. Assuming for simplicity that sales are exactly twice the amount of purchases, this adjustment would result in an additional 2,594 GWh of sales and only 1,297 GWh of purchases. Based on the pricing detailed above, the revenue from sales would be $78.1 million and the expense from purchases would be $46.3 million. The net result of these sales and purchases would be a net reduction to NPC of $31.7 million.

Q. IS IT APPROPRIATE TO USE HISTORICAL PRICING FOR THESE OUT-OF-MODEL TRANSACTIONS?

A. No. Assigning pricing based on historical gains or losses on forward transactions, as it appears the Company has done in this case,[21/] has no bearing on the gains or losses that will ultimately be incurred by the Company in the test period. The historical gains and losses on

[21/] PAC/100 at 30:1-3.

hedging transactions are indicative of changing market conditions between the time that the hedge is entered into and the prompt period. The historical data is reflective of market conditions in the historical period, which will not correspond to the market conditions implicated by the forward prices in the Company's power cost forecast.

c. Bid-Ask Spread

Q. WHAT IS THE SECOND ASPECT OF THE COMPANY'S SYSTEM BALANCING ADJUSTMENT?

A. The second aspect of the Company's adjustment is to incorporate a bid-ask spread into the hourly market prices included in the GRID model. These spreads are calculated based on a historical comparison between the revenues or expense associated with actual forward trades made by the Company relative to the ultimate monthly index price calculated by Intercontinental Exchange ("ICE"), separate for both sales and purchases.

Q. DO YOU AGREE WITH THIS ADJUSTMENT?

A. No. Comparing the average revenue or expense from hourly transactions to the monthly index price does not make sense. For example, it is expected that the average hourly revenue from sales made by the Company over the course of a month will be different than the overall monthly index price published by ICE. It simply depends on the timing of when the Company makes the sales transactions that will determine whether the average hourly price realized by the Company is ultimately higher or lower than the monthly index prices. If the Company sells more power in hours when prices are lower than the monthly average, the average rate that it recognizes is expected to be less than the monthly index price. Similarly, if the Company sells more in hours when prices are higher than the monthly average, the average rate that it recognizes is expected to be more than the monthly index price.

Q. DOES THIS ADJUSTMENT ALSO REFLECT HISTORICAL GAINS OR LOSSES BETWEEN THE FORWARD AND PROMPT PERIOD?

A. Yes. The bid-ask spreads calculated by the Company also reflect the impact of changing market prices between the period that the transaction was made and the ultimate spot price. These gains and losses, however, have no bearing on the bid-ask spreads between the rate at which the Company can buy and sell in the market.

Q. WHAT ARE THE BID-ASK SPREADS THAT THE COMPANY PROPOSES?

A. Based on the Company's workpapers, its proposal would result in a bid-ask spread that is on average $7.25/MWh. This amount exceeds any estimate of a bid-ask spread in power markets that I am aware of, including prior estimates of the Company. For example, in its 2008 IRP, the Company used "an estimated bid-ask spread of $0.50 per MWh" to calculate wind integration costs.[22/] Confidential Table 2, below, details the bid-ask spreads proposed by the Company, as calculated in their workpapers.

CONFIDENTIAL TABLE 2

Company Proposed Bid-Ask Spreads ($/MWH)

[redacted]

22/ 2008 Integrated Resource Plan, Volume II, Appendix F at 273 (May 2009). Available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2008IRP/2008IRP_Vol2_5-28-09.pdf.

Q. ARE THESE BID-ASK SPREAD AMOUNTS REASONABLE?

A. No. In addition to being based on methodology that does not make sense, the results of the Company's bid-ask spread calculations are unreasonable. Modeling a $23.60/MWh and $33.80/MWh spread at the Mid-Columbia and California-Oregon Border markets, respectively, in heavy load hours in the month of February is not consistent with what should be expected in the test period. A more reasonable bid-ask spread is likely more in line with the Company's prior estimates of approximately $0.50/MWh.

Q. HAVE RECENT WEATHER ANOMALIES IMPACTED THE COMPANY'S CALCULATIONS?

A. Yes. In fact, based upon my review of the Company's calculations, the reason that the spreads were so high in February 2014 is due to the fact that power prices at Mid-Columbia exceeded $280/MWh in certain hours as a result of extraordinary weather and market conditions in the Northwest in the first half of that month. Reliance upon these conditions produces an unreasonable result, as the impact of historical weather events should be normalized out of power costs.

Q. DOES A BID-ASK SPREAD HAVE ANY BEARING ON THE UNDERLYING PROBLEM PRESENTED BY THE COMPANY?

A. No. Modeling a bid-ask spread, irrespective of the merits of such a methodology, has no relationship to the Company's alleged cost of balancing its system. In conventional power cost forecasting, a bid-ask spread is used to model market liquidity. In illiquid, and often inelastic, market hubs, the price to purchase incremental power may exceed the price at which it can be sold. There is often little empirical data, however, to calculate what the actual bid-ask spread will be for any given market. Accordingly, the Company has traditionally relied on the use of the market caps constraint in GRID to account for market liquidity, restricting the ability of the model to make sales based on historical sales levels.

Q. IS IT CONSISTENT TO MODEL LIQUIDITY USING BOTH A BID-ASK SPREAD AND MARKET CAPS?

A. No. Modeling both a bid-ask spread and market caps will double count the impact of market liquidity in the GRID model. Accordingly, to the extent that a bid-ask spread methodology is approved, the Company's market cap methodology must be removed. For purposes of the Company's calculation, eliminating market caps will reduce the impact of the system balancing adjustment by $6.4 million on a total-Company basis.

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT THE COMPANY'S CALCULATION?

A. Yes. The Company excluded a bid-ask spread in periods when its calculation would have yielded a negative bid-ask spread amount. [redacted]. Had the Company modeled these negative bid-ask spreads, the impact of its adjustment would have been reduced. In addition, the mere fact that the methodology could produce a negative bid-ask spread is further evidence of its flawed nature.

<u>d.</u> <u>Alternative Adjustment</u>

Q. IS THERE MERIT IN MODELING A BID-ASK SPREAD IN GRID?

A. Yes. I believe that it may be reasonable to incorporate a bid-ask spread into the GRID model in order to better model the liquidity constraints experienced by the Company in actual operation. In presenting its bid-ask spread proposal, the Company has overcome some of the technical hurdles that have previously prevented the use of this methodology to model market liquidity. Accordingly, I believe it is appropriate to use a bid-ask spread methodology as a replacement for the market cap liquidity constraint. While I do not agree with the use of the spreads based on the flawed calculation methodology, I would support a bid-ask spread amount of $0.50/MWh, which is consistent with bid-ask spread amounts previously reported by the Company.[23] That is, the GRID model will be capable of selling at a price that is $0.25/MWh below the average market prices and will be capable of buying at a price that is $0.25/MWh above the average market prices.

Q. WHAT IS THE IMPACT OF YOUR ALTERNATIVE PROPOSAL?

a. Adopting this alternative proposal will result in a reduction to NPC of $6.9 million on a total-Company basis, with $1.7 million allocated to Oregon.

<u>e. System Balancing, Summary</u>

Q. PLEASE SUMMARIZE YOUR TESTIMONY ON THE COMPANY'S SYSTEM BALANCING ADJUSTMENTS.

A. The Company has presented a pair of adjustments that will collectively result in a $31.3 million increase to NPC on a total-Company basis. The alleged purpose of these adjustments—that there is a systematic cost associated with making hedging transactions in forward markets—is not supported by industry practice and does not represent costs that are properly includible in a power cost forecast. Accordingly, I recommend that the Commission reject the Company's proposal regarding these system balancing costs and adopt my alternative proposal, which will incorporate a $0.50/MWH bid-ask spread into the hourly GRID market prices as a replacement for the market cap methodology. Collectively, the removal of the Company's proposed adjustment and the adoption of my alternative recommendation will result in a $38.1 million total-Company reduction to NPC, with $9.4 million allocated to Oregon.

---

[23] 2008 Integrated Resource Plan, Volume II, Appendix F at 273 (May 2009). Available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2008IRP/2008IRP_Vol2_5-28-09.pdf.

III. RESERVES

Q. HOW DOES THE COMPANY MODEL RESERVES IN GRID?

A. The Company models reserves based on the data developed in the 2014 Wind Integration Study ("2014 WIS"), Appendix H to the Company's 2015 IRP. Rather than use the overall integration rate calculated by the IRP models, however, the Company uses the detailed forecast error data developed in the 2014 WIS to forecast a level of reserves that is representative of the load and wind profiles modeled in GRID in the test period. Based on this analysis, the Company's workpapers forecast that [redacted] aMW of reserves, consisting of both regulation and load-following reserves, are required in the test period.

Q. HOW DID THE COMPANY CONVERT THIS ANNUAL RESERVE REQUIREMENT INTO AN HOURLY RESERVE REQUIREMENT IN GRID?

A. The GRID model was not programmed to model hourly reserves as the Company has proposed in this proceeding.[24/] It was programmed to model a single annual reserve requirement for each balancing area. In order to simulate the impact of an hourly reserve requirement, the Company performed a series of complicated workarounds, including the creation of two fictitious geothermal resources with reserve attributes that are varied in each hour of the year. Using these fictitious geothermal resources, the Company shaped the net reserve amount in the GRID model to correspond to the Company's hourly reserve calculation.

Q. DO YOU AGREE WITH THIS HOURLY RESERVE SHAPING METHODOLOGY?

A. Due to the complexity, I have not been able to come to the conclusion that the Company's hourly reserve modeling methodology does, in fact, function as intended in the context of the overall GRID model logic. There may be some unintended consequences in the model associated with using a fictitious geothermal resource to model hourly reserves that the

---

24/ PAC/100 at 37:19-39:2.

Company has not addressed. Notwithstanding, I do believe it is appropriate to model hourly reserve requirements. An annual reserve requirement will typically overstate the cost of reserves in peak load hours, when the need for "INC" reserves is reduced due to an expectation that loads will decline in subsequent hours. Thus, it is typically more accurate from a cost perspective to model reserves on an hourly basis.

Q. WHAT ASPECT OF RESERVE MODELING DOES YOUR TESTIMONY DISCUSS?

A. My testimony discuses three aspects of the Company's reserve modeling. First, the Company's calculations assume that the Company regulates at a 99.7% confidence interval, when in actual operations the Company operates at a Control Performance Standard ("CPS") 2 standard that is closer to 65%. Second, while it did calculate incremental load following reserve benefits associated with NV Energy joining the EIM, the Company did not account for the additional load-following reserve diversity savings that will be achieved when Puget Sound Energy and Arizona Public Service Company join the market in October 2016. Third, the Company did not account for the impacts of the additional dynamic transfer capability as a result of an asset exchange with Idaho Power Company. The following sections address each of these issues, as well as a correction to the Company's calculation.

a. Regulation Reserve Correction

Q. PLEASE DESCRIBE THE CORRECTION THAT YOU PROPOSE TO THE COMPANY'S CALCULATION OF REGULATION RESERVES INPUT INTO THE MODEL.

A. The Company has contracts with several industrial customers located in its eastern balancing area that provide it with load following reserves. The Company's GRID modeling, however, allowed the reserves from these contracts to apply to both load following and regulation reserves. I recommend that the calculation of reserves from these contracts be restricted only to include load following reserves. The impact of this correction is a $2.6 million increase to NPC on a total-Company basis, with $0.7 million allocated to Oregon.

b. Reliability Metric

Q. WHAT IS THE ISSUE WITH THE RELIABILITY METRIC USED BY THE COMPANY TO MODEL RESERVES?

A. The 2014 WIS data used by the Company to calculate following and regulation reserve requirements was based on a 99.7% confidence interval metric, the equivalent of three standard deviations.[25/] In actual operations, however, the Company does not operate to such a high reliability metric. As a result of the Reliability Based Control Field Trial, the Company has been able to maintain a high degree of system reliability while operating at reliability metric that is much lower. For example, over the period 2012 through 2013, the Company's actual reliability performance, measured based on CPS2, was on average 61.7% for the western balancing area and 65.2% for the eastern balancing area.[26/] In addition, as a result of its participation in the EIM, the Company will likely be able to operate at an even lower metric, without impacting the level of service provided to customers. In recognition of these facts, I recommend that the hourly reserve calculations performed for purposes of GRID modeling be based on a 90% confidence interval. This is a very conservative reflection of the Company's actual reliability performance and will result in an approximate $11.2 million reduction to NPC on a total-Company basis, with $2.8 million allocated to Oregon.

Q. HOW HAS THE COMPANY HISTORICALLY DEVELOPED THE CONFIDENCE INTERVAL FOR CALCULATING RESERVES?

A. In previous wind integration studies, the confidence interval used to calculate reserves was tied directly to historical CPS2 performance. CPS2 performance is calculated pursuant to BAL-

[25/] In re PacifiCorp, dba Pacific Power's 2015 Integrated Resource Plan, Docket No. LC 62, 2015 Integrated Resource Plan, Volume II, Appendix H – Wind Integration at 115.

[26/] Confidential Exhibit ICNU/103 at 10-11 (the Company's Response to ICNU 65, Attach. ICNU 65).

001-01a, a North American Electric Reliability Corporation (“NERC”) reliability standard governing area control error (“ACE”).[27/] Under CPS2, the Company is required to maintain ACE within a specified threshold called “L_{10}” in greater than 90% of measurement periods.[28/] The Company previously considered the CPS2 measurement to be the equivalent of the confidence interval used to calculate reserves in its wind integration studies. For example, in the 2010 Wind Integration Study, the Company justified the use of a 97% confidence interval measurement, stating “average CPS2 performance for PacifiCorp’s East and West Balancing Authority Areas over the period 2004 to 2009 was just below 97%. As the goal of this Study is to incorporate wind integration in PacifiCorp’s current operations, the CPS2 performance of 97% was emphasized in these calculations.”[29/] In the 2014 WIS, however, the Company has used a higher confidence interval of 99.7%, despite the fact that actual CPS2 performance has declined in recent years.

Q. WHAT HAS THE COMPANY’S CPS2 PERFORMANCE BEEN IN RECENT YEARS?

A. In contrast to the 97% performance over the period 2004 to 2009, CPS2 performance over the period 2012 through 2014 has declined to 61.7% for the western balancing area and 65.2% for the eastern balancing area. This is detailed in Table 3 below.

27/ NERC Standard BAL-001-01a at 3. Available at: http://www.nerc.com/files/BAL-001-0_1a.pdf.

28/ Id.

29/ PacifiCorp, 2010 Wind Integration Study at 19. Available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/PacifiCorp_2010WindIntegrationStudy_090110.pdf.

TABLE 3
Actual CPS2 Measurements for Calendar Years 2012 through 2014
(Average of Monthly)

	2012	2013	2014	Average
West	62.0%	63.9%	59.2%	61.7%
East	75.6%	64.4%	55.6%	65.2%

Q. WHY HAS THE COMPANY'S CPS2 PERFORMANCE DECLINED SINCE THE 2010 WIND INTEGRATION STUDY?

A. On March 1, 2010, NERC began a pilot program in the Western Interconnection called the Reliability Based Control ("RBC") Field Trial. Under the RBC Field Trial, participating Balancing Authorities, including the Company, were allowed to waive their compliance with CPS2. It was generally recognized that CPS2 did not account for the fact that the frequency bias between balancing authorities is often offsetting. As a result, the CPS2 requirement was causing utilities to hold an unnecessarily high level of reserves in order to maintain regional reliability. While NERC still requires utilities to report their CPS2 performance, the RBC Field Trial produced a more favorable formula to measure reliability performance that recognized the offsetting regulation requirements between balancing authorities. This new formula has ultimately been documented as Requirement R2 in NERC standard BAL-001-2 and is commonly referred to as BAAL.[30/]

Q. IS THE COMPANY'S RESERVE REQUIREMENT EXPECTED TO DECLINE AS A RESULT OF BAAL?

A. Yes. Under the new BAAL reliability formula, it is expected that reserve requirements should decline. Notwithstanding, the Company has increased the confidence interval used to calculate reserves since BAAL was enacted. Because the Company is now estimating reserves based on

[30/] NERC Standard BAL-001-2 at 8. Available at http://www.nerc.com/files/BAL-001-2.pdf.

a higher, 99.7% confidence interval, the reserve reductions associated with its participation in the RBC Field Trial are not being properly incorporated into the Company's GRID modeling.

Q. HOW DID THE COMPANY DEVELOP THE 99.7% CONFIDENCE INTERVAL?

A. The 2014 WIS provides little explanation regarding the 99.7% confidence interval other than it corresponds to three standard deviations.[31/] While it is questionable why a standard deviation measurement should apply to a non-normal distribution of forecast errors, it is clear that the Company did not consider its historical reliability performance when calculating the 99.7% confidence interval. It is also clear that the Company did not perform any calculations to forecast its reliability performance in future periods.

Q. HAS THE WIS TECHNICAL REVIEW COMMITTEE COMMENTED ON THE USE OF BAAL TO CALCULATE RESERVES?

A. Yes. In the 2012 Wind Integration Study, the Technical Review Committee criticized the Company for not appropriately accounting for the reserve savings associated with the RBC Field Trial and BAAL, stating as follows:

> On page 12 there is discussion regarding the percentage exceedence that is used for the reserve calculation. In a footnote, PacifiCorp says that they have not been operating to CPS2 since March 2010 because it is participating in the Balancing Area ACE Limit (BAAL or RBC, Reliability Based Control) field trial. While they insist that the reserve exceedence should be 99.7%, their effective CPS2 performance during RBC is probably closer to 65-70% [....] PacifiCorp has not persuasively justified the 99.7-L_{10} tolerance level. The entire analysis consisting of millions of calculations and hundreds of megabytes of spreadsheets rests upon this one assumption. Deciding this single input strongly influences the final answer. There is no path from the actual reliability requirements to the input assumption used, nor is there even an intuitive guideline. In this respect, the 2010 wind integration study was superior because the tolerance target used was loosely driven by CPS2.[32/]

[31/] Docket No. LC 62, 2015 Integrated Resource Plan, Volume II, Appendix H – Wind Integration at 115.

[32/] 2012 Wind Integration Study Technical Review Committee (TRC), PacifiCorp 2012 Wind Integration Study Technical Memo at 7-8. Available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/2012WIS/Pacificorp_2012WIS_TRC-Technical-Memo_5-10-13.pdf

Q. DID THE COMPANY RESPOND TO THIS CRITICISM IN THE 2014 WIS?

A. No. While there is reference to this Technical Review Committee concern, the Company did not perform any concrete analysis in the 2014 WIS to demonstrate that a 99.7% confidence interval is consistent with the Company's actual or forecast reliability performance. The Company has presented no basis to explain why the use of 99.7% is any more accurate than any other value, such as a 90.0% confidence interval, or a 95.0% confidence interval.

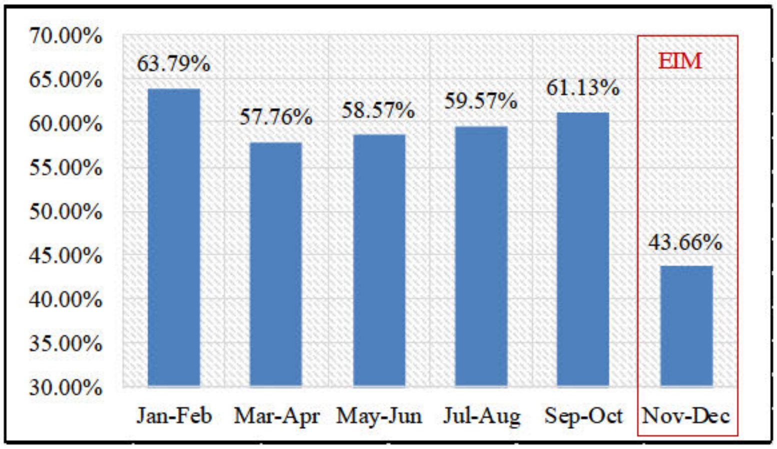
Q. HAS PARTICIPATION IN THE EIM FURTHER REDUCED THE RELIABILITY STANDARD THAT MUST BE MET BY THE COMPANY?

A. Yes. As a result of the EIM, the Company now has the ability to rebalance its system on a sub-hourly basis. It has also gained additional operational efficiencies through the adoption of the California Independent System Operator ("Cal-ISO") Security Constrained Economic Dispatch ("SCED") model. These two aspects of the Company's participation in the EIM—which have traditionally been referred to as "within-hour" and "intra-regional" EIM benefits, respectively—will have a positive impact on the overall level of reserves that the Company must hold relative to historical data. The Company's reserve modeling, however, does not address these positive aspects of the EIM. For purposes of this proceeding, adopting a more realistic confidence interval will result in reserve calculations that are more representative of the "within-hour" and "intra-regional" benefits previously forecast in connection with the EIM. While further adjustment may be warranted, for purposes of this proceeding, this will suffice.

Q. HAS THE COMPANY BEEN ABLE TO REDUCE ITS CPS2 PERFORMANCE AS A RESULT OF PARTICIPATION IN THE EIM?

A. Figure 2, below, details the Company's CPS2 performance calculation over 2014, including November 2014 and December 2014, when the EIM began operations.

FIGURE 2
Bi-Monthly Average CPS2 Performance
Calendar Year 2014



As can be noted from Figure 2, there was a material reduction to the CPS2 measurements in the period of November 2014 and December 2014, corresponding to the Company's entrance into the EIM. This is an indication that the Company has been able to relax the level of reserves being held, while maintaining a high degree of system reliability, due to its participation in the EIM.

Q. WHAT LEVEL OF CONFIDENCE INTERVAL DO YOU PROPOSE TO BE USED IN THE GRID MODEL?

A. While I believe there would be merit in using a confidence interval corresponding to the Company's historical CPS2 performance of 61.7% for the western balancing area and 65.2% for the eastern balancing area, I propose to use a 90% confidence interval for the purpose of this proceeding, which is consistent with the lower bound of the CPS2 standard. In order to produce results that are less punitive for the Company, and until studies are preformed to support an appropriate confidence interval, the use of a 90% confidence interval in this proceeding will begin to move the Company towards its actual CPS2 performance.

Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?

A. Modeling reserves based on a 90% confidence interval, rather than a 99.7% confidence interval, will reduce NPC by $11.2 million on a total-Company basis, with $2.8 million allocated to Oregon.

c. PSE and APS Reserve Diversity

Q. DID THE COMPANY INCLUDE ANY RESERVE DIVERSITY BENEFITS ASSOCIATED WITH PSE AND APS JOINING THE EIM IN OCTOBER OF 2016?

A. No. While the Company included reserve diversity benefits associated with the NV Energy's participation in the EIM in October of 2015, it did not include any incremental flexibility reserve diversity benefits associated with the addition of PSE and APS in the fourth quarter of the test period, beginning in October 2016.

Q. WHAT ARE FLEXIBILITY RESERVE DIVERSITY BENEFITS?

A. The flexibility reserves savings represent the load following reserve savings associated with "aggregating the two systems' load, wind, and solar variability and forecast errors."[33/] These reserves savings, which are representative of having a more diverse set of resources upon which to hold reserves, are distinct from the regulation reserve savings that will accrue to the Company as a result of moving to a sub-hourly market and scheduling paradigm.

Q. WHAT AMOUNT OF RESERVE SAVINGS DO YOU PROPOSE TO INCLUDE FOR PSE?

A. In September 2014, Energy Environmental Economics, Inc. ("E3"), the same firm that developed an original estimate of EIM savings between the Company and the Cal-ISO, published a "Benefits Analysis of Puget Sound Energy's Participation in the ISO Energy

---

33/ Energy Environmental Economics, Inc., PacifiCorp-ISO Energy Imbalance Market Benefits at 6-7 (Mar. 13, 2013). Available at: http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf.

Imbalance Market" (the "PSE E3 Study").[34/] In that report it was calculated that the addition of PSE to the EIM would result "in a 26.3 MW flexibility reserve reduction attributed to PSE and an incremental 48.2 MW reserve reduction attributed to the current EIM participants."[35/] The PSE E3 Study did not break-out the amount of reserves savings that would be attributable to each of the current EIM participants: Cal-ISO, PacifiCorp, and NV Energy. Due to the proximity between PSE and the Company, my expectation is that the majority of the 48.2 MW of reserve diversity benefits attributable to current EIM participants will flow to the Company. Notwithstanding, I propose a very conservative adjustment to attribute the 48.2 MW of reserve savings in accordance with the current EIM participants' peak loads. With peak loads of 45.0 GW, 10.4 GW, and 7.3 GW for Cal-ISO, PacifiCorp, and NV Energy, respectively, this attribution methodology will result in reserve savings of approximately 8.0 MW attributable to the Company.

Q. WHAT AMOUNT OF RESERVE SAVINGS DO YOUR PROPOSE TO INCLUDE FOR APS?

A. In April 2015, E3 published a report titled "APS Energy Imbalance Market Participation: Economic Benefits Assessment" (the "APS E3 Study").[36/] In that report, E3 calculated expected flexibility reserve savings as follows:

> Overall, APS's participation in the EIM provides incremental diversity to the full EIM footprint, reducing flexibility reserve requirements for current EIM participants by 83.4 MW on average, which is an 8% reduction compared to their requirements in the current EIM. APS's own flexibility reserve requirement is reduced by 52.2 MW on average, a 28% reduction from its requirements as a standalone BA.[37/]

[34/] PSE E3 Study (Sept. 2014). Available at: http://pse.com/aboutpse/EnergySupply/Documents/PSE-ISO_EIM_Report_wb.pdf.
[35/] Id. at 51.
[36/] APS E3 Study (Apr. 2015). Available at: http://www.caiso.com/Documents/ArizonaPublicService-ISO-EnergyImbalanceMarketEconomicAssessment.pdf.
[37/] Id. at 33-34.

Similar to the PSE study, the APS E3 Study did not break-out the reserve savings attributable to each of the current EIM participants. I propose to attribute these reserve savings in proportion to each utility's peak load, in the same fashion proposed for PSE above, resulting in reserve reductions attributable to the Company of 13.8 MW.

Q. DO THE RESERVE SAVINGS CALCULATED BY E3 FOR PSE AND APS POTENTIALLY OVERLAP?

A. Yes. Because APS was not included in the PSE study and PSE was not included in the APS study, the incremental reserve savings to the Company associated with the addition of these two participants cannot be combined using an arithmetic sum. I propose to add the two reserve savings values attributed to the Company using the root-sum-of squares formula to arrive at an amount that is representative of the combined impact between the two studies. Applying this formula will result in a total reserve savings of 16.0 MW.[38/]

Q. WHAT IS THE IMPACT OF MODELING THESE RESERVE SAVINGS IN THE GRID MODEL?

A. Incorporating this 16.0 MW reserve savings into the GRID model beginning on October 1, 2016, results in a reduction to NPC of $60,750 on a total-Company basis, with $15,020 allocated to Oregon.

<u>d. Idaho Power Asset Exchange</u>

Q. WHAT IS YOUR CONCERN WITH THE IDAHO POWER ASSET EXCHANGE?

A. On October 24, 2014, the Company entered into a Joint Purchase and Sale Agreement (the "Idaho Power Asset Exchange") with Idaho Power Company, which, among other things, provided that "[t]he Company's dynamic transfer rights from PacifiCorp's east Balancing Authority Area (PACE) to PacifiCorp's West Balancing Authority Area (PACW) will increase

---

38/ $\sqrt{8.0aMW^2 + 13.8aMW^2} = 16.0aMW$

from 200 megawatts (MW) to 400 MW."[39/] The Company claimed that this exchange would provide the Company with a great deal of additional operational flexibility between the Company's eastern and western balancing areas.[40/] Notwithstanding, the Company has not modeled this additional flexibility in the GRID model. Rather, the Company has proposed a modeling methodology that is more restrictive on how flexibility requirements are transferred between balancing areas. I propose a methodology that will properly account for this greater level of flexibility, allowing for flexibility reserve transfers between the eastern and western balancing areas.

Q. IS THE COMPANY'S PROPOSED MODELING CONSISTENT WITH YOUR UNDERSTANDING OF THE IDAHO POWER ASSET EXCHANGE?

A. No. My understanding is that the Idaho Power Asset Exchange will increase the amount of dynamic transfer capability, not reduce the amount of dynamic transfer capability.

Q. DOES THE COMPANY'S MODELING ALSO CONTRADICT ITS PARTICIPATION IN THE EIM?

A. Yes. As a result of its participation in the EIM and the use of the Cal-ISO SCED model to manage inter-hour operations, the Company now has greater ability to transfer flexibility reserve requirements between balancing authorities.

Q. WHAT DO YOU PROPOSE?

A. For purposes of this proceeding, I propose a methodology that will allow the model to transfer an amount of flexibility reserves bi-directionally between balancing authorities.

Q. HOW DID YOU PERFORM THIS MODELING?

A. I performed two runs. In the first run, I analyzed the hourly net variable cost benefit of transferring 50 MW of load following reserves from east to west. In the second run, I analyzed

39/ In re PacifiCorp, dba Pacific Power, and Idaho Power Company Request for Approval to Exchange Certain Transmission Assets Associated with the Jim Bridger Generation Plant, Docket No. UP 315, PAC/400 at 2:7-9.

40/ Id. at 5:21-6:20.

the net variable cost benefit of transferring 50 MW of load following reserves from west to east. I then determined the most economic allocation of the 50 MW of reserves between the balancing areas.

Q. WOULD IT BE ECONOMIC IN SOME HOURS FOR THE COMPANY TO TRANSFER MORE THAN 50 MW OF RESERVES BETWEEN BALANCING AREAS?

A. Yes. My understanding is that under the Idaho Power Asset Exchange up to 400 MW of reserves could be transferred between balancing areas, depending on the utilization of the transmission rights. However, to avoid the need to perform successive runs at various reserve transfer levels, I only modeled a 50 MW flexibility reserve transfer between balancing areas for purposes of this adjustment. Ultimately, this methodology should be expanded to determine if greater levels of flexibility reserve transfers are warranted.

Q. WHAT IS THE IMPACT OF APPLYING THIS METHODOLOGY?

A. This methodology will result in a reduction to NPC of $1.3 million on a total-Company basis, with $0.3 million allocated to Oregon.

IV. INTER-REGIONAL EIM DISPATCH

Q. DID THE COMPANY INCLUDE A PROVISION FOR INTER-REGIONAL EIM DISPATCH BENEFITS IN NPC?

A. Yes. The Company included in NPC approximately $8.5 million of inter-regional EIM dispatch benefits in connection with its EIM transfer capability with the Cal-ISO.[41/] This amount consisted of $7.5 million of benefits related to EIM exports and $1.0 million of benefits related to EIM imports.[42/] The calculation was based on the Company's actual experience in the months of December 2014 and January 2015 and was limited to transactions

---

41/ PAC/100 at 18-19.
42/ Id.

with the Cal-ISO, excluding any expected transactions with NV Energy, PSE, and APS in the test period.

Q. WHAT ARE INTER-REGIONAL DISPATCH BENEFITS?

A. Inter-regional dispatch benefits represent the economic margins earned in connection with sub-hourly energy transfers. Each energy transfer in the EIM is intended to be priced such that it is economic for both the transferor and the transferee; exports are priced to exceed the cost of increasing output from the marginal resource, and imports are priced to be less than the cost of reducing output from the marginal resource. Thus, each EIM sub-hourly energy transfer is expected to produce a degree of economic margin to the EIM participant.

Q. HOW DID THE COMPANY CALCULATE THE INTER-REGIONAL EIM DISPATCH BENEFITS IN THE TEST PERIOD?

A. The Company evaluated the historical margins earned as a result of EIM transfers with the Cal-ISO in the months of December 2014 and January 2015, separately for both EIM imports and exports.[43/] The Company, determining that transmission capability was not a limiting factor, annualized the actual inter-regional benefits achieved in those two months, simply multiplying the two-month actual benefits by a factor of six.[44/]

Q. DO YOU AGREE WITH THE COMPANY'S CALCULATION?

A. I have identified two concerns with the Company's calculation. First, the Company did not properly reflect expected seasonality in inter-regional dispatch benefits. Second, the Company did not account for the inter-regional dispatch benefits associated with the addition of new EIM participants NV Energy, PSE and APS. Both of these issues will be discussed below.

43/ PAC/100 at 16:7-19:3.
44/ Id.

a. Seasonality

Q. DID THE COMPANY PROPERLY REFLECT THE SEASONALITY OF EIM BENEFITS?

A. No. The Company bases its calculation of the economic margins with the Cal-ISO on two months of data, December 2014 and January 2015. These two winter months, however, are not indicative of the level of inter-regional dispatch benefits expected over the course of the year. Rather, as a result of summer peaking demand in California, it is expected that the EIM will produce inter-regional dispatch benefits that are greatest in the summer months.

Q. HOW DO YOU PROPOSE TO INCORPORATE SEASONALITY INTO THE INTER-REGIONAL DISPATCH BENEFITS WITH THE CAL-ISO?

A. I propose to shape the economic margins used to calculate EIM dispatch benefits associated with the Cal-ISO based on the relative market spreads between Mid-Columbia and California-Oregon Border ("COB") market prices between the measurement period—December 2014 and January 2015—and the test period. For exports, the economic margins would be increased in proportion to the increases in the market spreads between Mid-Columbia and COB. For imports, the economic margins would be increased as the market spreads between Mid-Columbia and COB decline. This will account for the expected seasonality of the economic margins, as well as potential changes in the economic margins between the measurement period and the test period.

Q. WHY IS IT APPROPRIATE TO SHAPE EIM MARGINS BASED ON THE MARKET SPREADS IN THE FORWARD PRICE CURVE?

A. The economic margins earned on EIM transfers between the Company and Cal-ISO are based on the supply and demand characteristics of the Northwest and California. If prices in California are substantially higher than prices in the Northwest, the economic margins earned on EIM exports are expected to be relatively high. Similarly, if prices in California are equal to prices in the Northwest, the economic margins earned on EIM exports are expected to be relatively low. Thus, the spreads between the market prices in the two regions should reflect a fair indication of the incremental economic margins that will be achieved in future months.

Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?

A. The calculation of this adjustment has been detailed in Confidential Exhibit ICNU/104. The result is a $1.5 million reduction to total-Company NPC, with $0.4 million allocated to Oregon.

b. New EIM Participants

Q. DID THE COMPANY MODEL AN INCREASE IN INTER-REGIONAL DISPATCH BENEFITS IN CONNECTION WITH THE ADDITION OF NV ENERGY, PSE AND APS INTO THE MARKET?

A. No. The Company did not model additional economic margins associated with the entrance of new participants into the EIM market. The only inter-regional dispatch benefits modeled by the Company in the test period were with the Cal-ISO.

Q. WHY SHOULD INTER-REGIONAL DISPATCH BENEFITS ASSOCIATED WITH THESE NEW ENTITIES BE INCLUDED IN NPC?

A. This category of benefits represents actual energy transfers that the Company will make in the test period. Regardless of whether the Company ultimately imports or exports energy from these new participants, it will earn additional economic margins as a result of the EIM transactions. Accordingly, it is known that some level of benefit will be recognized by the Company in the test period associated with these entities.

Q. WHAT LEVEL OF BENEFIT SHOULD BE EXPECTED IN THE TEST PERIOD?

A. The ultimate benefit will depend on the level of transfer capability between the various entities, as well as the ultimate amount of energy that is transacted in the test period. In December 2014 and January 2015 for example, the Company maintained approximately 400 MW of bidirectional transfer capability with the Cal-ISO. Yet, the Company only transacted approximately [redacted] aMW of sub-hourly energy transfers ([redacted] aMW of exports and [redacted] aMW of imports) in the period, approximately [redacted] its overall capability.[45/] The average economic margin on these sub-hour energy transfers was approximately $[redacted]/MWh, resulting in an average monthly benefit of $[redacted].[46/]

Q. HOW MUCH EIM TRANSFER CAPABILITY WILL THE COMPANY HAVE WITH NV ENERGY IN THE TEST PERIOD?

A. The benefits report published by E3 for NV Energy did not model any transfer capability between the Company and NV Energy. Notwithstanding, NV Energy has subsequently stated in a tariff filing with FERC that that it will have 430 MW of EIM transfer capability with the Company, consisting of 300 MW of bidirectional transfer capability from Red Butte and 130 MW of transfer capability from Gonder.[47/] This conflicts with the Company's statements in testimony filed subsequent to the NV Energy tariff filing that, for purposes of the EIM, no direct connection was expected to be available in the test period between the Company and NV Energy.[48/]

Q. HOW MUCH EIM TRANSFER CAPABILITY WILL THE COMPANY HAVE WITH PSE?

The PSE E3 Study assumed that the transfer capability between PSE and the Company would range from 300 MW to 900 MW.[49/] These transfers will likely occur at, or in the proximity to, the Mid-Columbia market.

45/ PAC/105 at 1.
46/ Id.
47/ FERC Docket No. ER15-1196, NV Energy's Proposed Amendments to Its Open Access Transmission Tariff to Provide for Voluntary Participation in the Energy Imbalance Market with the California Independent System Operator at 27 (Mar. 6, 2015).
48/ PAC/100 at 20:13-18.
49/ PSE E3 Study at 20.

Q. HOW MUCH EIM TRANSFER CAPABILITY WILL THE COMPANY HAVE WITH APS?

A. The APS E3 Study assumed that 600 MW of transfer capability would be available between APS and the Company.[50/] The interconnection between APS and the Company is primarily at the Four Corners market. In addition, the APS E3 Study assumed that APS would have an additional 2,500 MW of transmission capability with the Cal-ISO.[51/]

Q. BASED ON THESE LEVELS OF TRANSFER CAPABILITY, WHAT LEVEL OF ADDITIONAL EIM DISPATCH BENEFITS DO YOU PROPOSE?

A. I propose to calculate the incremental inter-regional dispatch benefits associated with this level of transfer capability using a simple formula. Similar to the Company's experience with the Cal-ISO, my adjustment would assume that only one-third of the available EIM transfer capability would be utilized to effectuate sub-hourly energy transfers. For PSE, this calculation would be based on the low transfer capability range presented in the PSE E3 Study. For purposes of pricing energy transfers, I would then assume a $1.66/MWh economic margin, which represents the economic margins that the Company actually earned on sub-hourly transfers with the Cal-ISO in the first months of EIM operations discounted by one-half to reflect uncertainty. The result of this analysis is detailed in Table 4, below.

50/ APS E3 Study at 20.
51/ Id.

TABLE 4
Inter-regional Dispatch Benefit Calculation of New EIM Participants

ln	Description	Ref	NV Energy	PSE	APS	Total
1	Transfer Capability (MW)		430	300	600	1,330
2	EIM Energy Transfers (aMW)	[1]*33%	142	99	198	439
3	Hours In EIM		8784	2208	2208	
4	Energy Transfers (MWh)	[2]*[3]	1,246,450	218,592	437,184	1,902,226
5	Economic Margin ($/MWh)		$ 1.66	$ 1.66	$ 1.66	$ 1.66
6	Inter-Regional Dispatch Benefit ($)	[4]*[5]	$ 2,069,106	$ 362,863	$ 725,725	**$ 3,157,694**

Q. PLEASE SUMMARIZE YOUR ADJUSTMENT PROPOSAL REGARDING THE INTER-REGIONAL DISPATCH BENEFITS ASSOCIATED WITH NEW EIM PARTICIPANTS?

A. The estimates detailed in Table 4, above, are based on conservative calculations of the inter-regional dispatch benefits that the Company will be capable of receiving in connection with the entry of NV Energy, PSE and APS into the EIM. Accordingly, I propose to increase the level of inter-regional dispatch benefits included in NPC by $3.2 million on a total-Company basis, with $0.8 million allocated to Oregon.

V. HERMISTON CONTRACTS

a. Prudence

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR CONCERN WITH THE HERMISTON PURCHASE CONTRACT.

A. The Company is a 50% owner of the Hermiston power plant located in Umatilla County, Oregon. The remaining 50 percent is owned by the Hermiston Generating Company ("HGC"), which is also the operator of the facility. The Hermiston power plant consists of two 245 MW

1x1 Combined Cycle Combustion Turbines, totaling 490 MWs of capacity. In addition to its ownership share, the Company currently purchases HGC's 50% of share of Hermiston under a long term PPA—the Hermiston Purchase contract—that expires on July 1, 2016. Pursuant to the PPA, however, the Company had the option to extend the PPA [redacted][53]

Q. DID THE COMPANY ELECT TO EXTEND THE CONTRACT?

A. No. The Company concluded that it was [redacted][54]

Q. HOW DID THE COMPANY MAKE THIS DETERMINATION?

A. [redacted][55] [redacted][56]

Q. WHAT IS YOUR CONCERN WITH THE COMPANY'S DECISION?

A. There is a problem with the Company's overall approach to capacity planning within the context of its IRP models. The Company's overall methodology makes an incorrect assumption that the winter peak in the western balancing area will always be satisfied, as long as capacity is available to meet the larger, summer peak loads driven by the eastern control area. As a result of transmission limitations and the seasonality of many of the summer capacity resources included in the IRP, however, this is not an accurate assumption. The result

52/ See Confidential Exhibit ICNU/103 at 1 (the Company's Response to ICNU DR 53).
53/ Id. at 3-4 (the Company's Response to ICNU DR 54, Attach. ICNU 54).
54/ Id. at 3 (the Company's Response to ICNU DR 54, Attach. ICNU 54).
55/ Id. at 4-9 (the Company's Response to ICNU DR 54, Attach. ICNU 54).
56/ Id.

of this incorrect assumption is that the Company is potentially making incorrect decisions and adding unnecessary costs on its system.

Q. CAN THE COMPANY IMPORT UNLIMITED CAPACITY INTO THE NORTHWEST?

A. No. The Company is only capable of importing a limited amount of capacity, primarily from Jim Bridger, into the Northwest. The amount of winter capacity that can be imported, however, is already being fully utilized. Because there is no unused long-term transmission capacity to deliver additional capacity between the two balancing areas and the Company has no plan to build any, the development of a new capacity resource in the eastern balancing area for purposes of meeting summer peaks will provide no additional capacity to be used to meet winter peaks in the West.

Q. WHY IS THIS A PROBLEM IN THE COMPANY'S IRP MODELING?

A. The capacity additions in the Company's 2015 IRP consists primarily of summer peak capacity purchases.[57/] These purchases are designed solely for the purpose of meeting summer loads and provide no winter peaking capacity to the West. Accordingly, it is not clear how the Company intends to meet winter peak loads in its IRP. Since it needs capacity to meet both the summer and winter peak, ignoring the winter peak in its capacity expansion models is a gross omission by the Company—particularly as the summer peak is only approximately 1,100 MW larger than the winter peak.

Q. WHY DO YOU BELIEVE THAT THE COMPANY'S MODELING OF THE HERMISTON PURCHASE CONTRACT IS EVIDENCE OF IMPRUDENCE?

A. When the Company analyzed the possibility of extending the Hermiston Purchase contract, it did so on the basis of satisfying its summer peak, and the potential deferral of summer peaking

[57/] PacifiCorp 2015 IRP, Volume II, App. K at 204.

resources in the mid-to-late 2020's timeframe.[58/] This is concerning because the Company has recently performed a study in the 2015 IRP indicating that a winter peaking resource may be needed in the near-term to meet peak loads. Sensitivity S-10, a stand-alone capital expansion plan for the western balancing area based on a winter peak, demonstrated that a winter peaking resource may be needed as early as 2020 to meet loads in the western balancing area.

Q. WHAT DO YOU RECOMMEND?

A. Because it is not clear that the Company made the right decision to terminate the Hermiston Purchase contract, I recommend that the Commission make a finding that the Company's decision-making was imprudent on the basis that the Company did not analyze the winter peaking benefits of that resource. While such a decision would have no near-term implications to the Company, ratepayers must be held harmless to the extent that it is ultimately necessary to build a winter peaking resource as a result of the Company's decision not to extend the contract.

b. Unused Point-To-Point Transmission

Q. WHAT IS YOUR RECOMMENDATION RELATED TO THE HERMISTON POINT-TO-POINT TRANSMISSION CONTRACT?

A. The Company currently has rights to 490 MWs of point-to-point transmission on the Bonneville Power Administration's system to deliver power from the Hermiston power plant to its system. The total cost of this transmission in the test period was forecast to be $[redacted]. I recommend eliminating the portion of the cost associated with this transmission contract that was related to the expired Hermiston Purchase contract. This will result in a reduction to NPC of $0.2 million on a total-Company basis, with approximately $54,336 allocated to Oregon.

58/ See Confidential Exhibit ICNU/103 at 2-9 (the Company's Response to ICNU DR 54, Attach. ICNU 54).

Q. WHY DO YOU PROPOSE TO REMOVE THIS AMOUNT RELATED TO THE HERMISTON PURCHASE CONTRACT?

A. According to the Company's workpapers, the Hermiston point-to-point transmission contract—which provides the Company with transmission capability equal to the full 490 MW of capacity from the Hermiston power plant—[redacted]. Because the Company will no longer have rights to the full 490 MW of capacity from the Hermiston power plant, half of the capacity under the transmission contract will no longer be used and useful beginning on July 1, 2016. In addition, because the Company appears to have renewed the full amount of capacity for this contract after the decision not to extend the Hermiston Purchase contract had been made, the unneeded portion of the point-to-point transmission contract is also not prudent. For these reasons, I believe it is appropriate to eliminate one-half of cost of this transmission contract from rates beginning on July 1, 2016, which is the expiration date of the Hermiston Purchase contract.

VI. OUTAGE MODELING

Q. HOW HAS THE COMPANY PROPOSED TO CHANGE ITS OUTAGE MODELING METHODOLOGY IN THIS PROCEEDING?

A. The Company has proposed to model outages dynamically based on discrete outage events over the four-year base period.[59] Based on the historical data, the Company developed an hourly schedule of outages for each plant, which it modeled in GRID in the test period.[60] This is in contrast to the methodology approved in Docket No. UM 1355, where the capacity and heat rates of plants are derated to simulate cost impacts of outages over the course of the test period. The impact of the Company's new methodology is a $0.7 million increase to NPC on a total-Company basis, relative to the methodology approved in Docket No. UM 1355.

---

[59] PAC/100 at 30:19-31:4.
[60] Id. at 32:22-25.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED METHODOLOGY?

A. No. Because the Company has developed the outage schedule based on an average over the four-year base period, its proposed methodology results in a pattern of frequent, short outages that is not representative of the pattern of outages experienced in actual operations. Frequent and short outages are expected to result in greater cost than longer, less frequent outages. This is expected because it is expensive for a resource to commit up and down as a result of an outage. In addition, as outages become increasingly short and frequent, it becomes more expensive for the overall resource portfolio to respond to the outages, having to ramp up and down in more frequent intervals than in actual operations.

There is also an issue regarding bias in the timing of outages. For example, the Company had several plants located in the Northwest that were on forced outage during the 2013-2014 winter peak months. Modeling a similar pattern in the test period may result in a skewed outage schedule that is not representative of normalized operations.

Q. WHAT DO YOU PROPOSE?

A. While there may be some merit in modeling a schedule of forced outages, the number of additional issues that must be resolved in this proceeding would outweigh the benefits of adopting the Company's proposed modeling methodology at this time. Accordingly, I propose that the Company continue to use the methodology approved in UM 1355. The Company's proposal in this case is complicated and will not result in a forecast that is any more accurate than those produced through the UM 1355 methodology. In addition, the UM 1355 methodology underwent extensive review by the parties, so it would be preferable not to adopt a new methodology at this time, without undertaking a similarly extensive review. Reverting back to the UM 1355 methodology will reduce NPC by $0.7 million on a total-Company basis, with $0.2 million allocated to Oregon.

VII. WIND ENERGY PROFILES

a. Avian Protection

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING MODELING OF AVIAN PROTECTION COSTS?

A. The Company has proposed to reduce the generation output from several Wyoming wind resource to reflect a small amount of energy expected to be lost as a result of avian protection curtailments.[61/]

Q. DO YOU AGREE WITH THIS PROPOSAL?

A. No. The wind resources in question created a great deal of controversy at the time they were built,[62/] so the Company should have an obligation to use the planning assumptions that were originally used to justify the facilities. In addition, the amounts in question are so small, representing only a fraction of the facilities' ultimate output, that a modeling adjustment to reflect avian curtailments is immaterial and will not result in a forecast that is any more accurate than the Company's current practice.

Q. WHAT IS YOUR PROPOSAL?

A. I propose that the Commission reject the Company's avian protection proposal. Eliminating the impact of the proposal will reduce NPC by $0.2 million on a total-Company basis, with $0.1 million allocated to Oregon.

61/ Id. at 39:3-40:14.

62/ See, e.g., In re PacifiCorp, dba Pacific Power, 2009 Renewable Adjustment Clause, Schedule 202, Docket No. UE 200.

b. Rolling Average

Q. WHAT IS THE COMPANY'S PROPOSAL WITH REGARD TO THE USE OF A ROLLING AVERAGE TO CALCULATE WIND PPA GENERATION OUTPUT?

A. The Company proposes to use a four-year rolling average to calculate the output from facilities acquired under a PPA.[63/] The impact of this change is material relative to its avian curtailment proposal above, resulting in a $5.8 million increase to total-Company NPC or $1.4 million allocated to Oregon.

Q. DO YOU AGREE WITH THIS PROPOSAL?

A. No. The Company should have an obligation to use the same profiles for ratemaking that it originally used to justify entering into the wind PPAs in question. The pricing negotiated by the Company for these contracts was developed based upon an assumed level of generation, and, to the extent that the Company's due diligence process under- or over-stated the generation profile, the Company should be responsible for the difference.

A. IS A FOUR-YEAR PERIOD AN APPROPRIATE TIME PERIOD TO NORMALIZE WIND OUTPUT?

A. No. Four years is too short of a period to estimate a normalized level of output from wind resources. Similar to hydro, the normalized output from a wind resource should be measured over a long period, such as 30 years, to determine the true normalized generation level of the resource. Simply using a four-year average will not remove the impact of recent weather patterns.

Q. WHAT DO YOU PROPOSE?

A. I propose that the Commission reject the Company's new normalization methodology, reducing the Company's filed NPC by the amounts detailed above.

[63/] PAC/100 at 40:15-41:8.

VIII. OTHER ISSUES

Q. HAVE YOU REVIEWED THE PRUDENCE OF THE COMPANY'S ENVIRONMENTAL UPGRADES AT THE JIM BRIDGER AND HAYDEN FACILITIES, AS REFLECTED IN NET POWER COSTS?

A. No. I have not reviewed the prudence of these upgrades, nor the associated increase in NPC, in this proceeding. While I am concerned with the rapidly escalating cost at the Jim Bridger power plant, as well as at the Bridger Coal Company mine, the issues surrounding the prudence of these investments are best suited to be reviewed in the context of the Company's next general rate proceeding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 296

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
2016 Transition Adjustment Mechanism.	)
	)
______________________________________	)

EXHIBIT ICNU/101

QUALIFICATION STATEMENT OF BRADLEY G. MULLINS

June 29, 2015

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I received Bachelor of Science degrees in Finance and in Accounting from the University of Utah. I also received a Master of Science degree in Accounting from the University of Utah. After receiving my Master of Science degree, I worked as a Tax Senior at Deloitte Tax, LLP, where I provided tax compliance and consulting services to multi-national corporations and investment fund clients. Subsequently, I worked at PacifiCorp Energy as an analyst involved in regulatory matters primarily involving power supply costs. I began performing independent consulting services in September 2013. I currently provide consulting services for utility customers, independent power producers, and qualifying facilities on matters ranging from power costs and revenue requirement to power purchase agreement negotiations.

Q. PLEASE PROVIDE A LIST OF YOUR REGULATORY APPEARANCES.

A. I have sponsored testimony in regulatory proceedings throughout the western United States, including the following:

- Wa.UTC, UE-143932: In re Complaint of The Walla Walla Country Club Against Pacific Power & Light Co.
- Or.PUC, UE 294: In re Portland General Electric Company, Request for a General Rate Revision
- Or.PUC, UM 1662: In re Portland General Electric Company and PacifiCorp dba Pacific Power, Request for Generic Power Cost Adjustment Mechanism Investigation
- Or.PUC, UM 1712: In re PacifiCorp, dba Pacific Power, Application for Approval of Deer Creek Mine Transaction

- Bonneville Power Administration, BP-16: 2016 Joint Power and Transmission Rate Proceeding
- Wa.UTC, UE-141368: In re Puget Sound Energy, Petition to Update Methodologies Used to Allocate Electric Cost of Service and for Electric Rate Design Purposes
- Wa.UTC, UE-140762: In re Pacific Power & Light Company, Request for a General Rate Revision Resulting in an Overall Price Change of 8.5 Percent, or $27.2 Million
- Wa.UTC, UE-141141: In re Puget Sound Energy, Revises the Power Cost Rate in WN U-60, Tariff G, Schedule 95, to reflect a decrease of $9,554,847 in the Company's overall normalized power supply costs
- Wy.PSC, 20000-446-ER-14: In re The Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming Approximately $36.1 Million Per Year or 5.3 Percent
- Wa.UTC, UE-140188: In re Avista Corporation, General Rate Increase For Electric Services, RE: Tariff WN U-28, Which Proposes an Overall Net Electric Billed Increase of 5.5 Percent Effective January 1, 2015
- Or.PUC, UM 1689: In re PacifiCorp, dba Pacific Power, Application for Deferred Accounting and Prudence Determination Associated with the Energy Imbalance Market
- Or.PUC, UE 287: In re PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism.
- Or.PUC, UE 283: In re Portland General Electric Company, Request for a General Rate Revision

- Or.PUC, UE 286: In re Portland General Electric Company's Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU)
- Or.PUC, UE 281: In re Portland General Electric Company 2014 Schedule 145 Boardman Power Plant Operating Adjustment
- Or.PUC, UE 267: In re PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-Out (adopting testimony of Donald W. Schoenbeck).

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 296

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
2016 Transition Adjustment Mechanism.	)
	)
	)

REDACTED EXHIBIT ICNU/102

EXCERPTS OF FEBRUARY 13, 2015 SEMI-ANNUAL HEDGING REPORT

June 29, 2015

Exhibit ICNU/102 is confidential pursuant to Protective Order No. 10-069 and has been redacted in its entirety.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 296

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
2016 Transition Adjustment Mechanism.	)
	)
	)

REDACTED EXHIBIT ICNU/103

RESPONSES TO ICNU DATA REQUESTS

June 29, 2015

UE 296/PacifiCorp
May 28, 2015
ICNU 2nd Set Data Request 0053

ICNU Data Request 0053

Please provide a brief description of all rights that the Company held to extend the Hermiston Purchase contract.

Confidential Response to ICNU Data Request 0053

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

The information provided is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

UE 296/PacifiCorp
May 28, 2015
ICNU 2nd Set Data Request 0054

ICNU Data Request 0054

Please provide any economic analyses performed for the purpose of evaluating an extension of the Hermiston Purchase contract.

Response to ICNU Data Request 0054

The Company conducted an analysis regarding whether to extend the Hermiston purchased power agreement under attorney-client privilege, which privilege is hereby waived by the Company. The analysis is commercially sensitive and confidential. Please refer to Confidential Attachment ICNU 54, which provides the Company's memorandum regarding analysis whether to extend the Hermiston purchased power agreement.

The information provided in the confidential attachment is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

Pages 3 - 9 of Exhibit ICNU/103 are confidential pursuant to Protective Order No. 10-069 and have been redacted in their entirety.

UE 296/PacifiCorp
June 9, 2015
ICNU 3rd Set Data Request 0065

ICNU Data Request 0065

Please provide a table detailing the Company's actual CPS2 compliance, on a monthly basis, over the period 2012 through 2014 (inclusive).

Response to ICNU Data Request 0065

Please refer to Attachment ICNU 0065 for the Control Performance Standards 2 (CPS2) monthly results.

Note: PacifiCorp tracks and measures compliance with Control Performance Standards 1 (CPS1), and tracks but does not measure compliance with CPS2 due to a change in standards. CPS2 has been replaced with participation in the WECC Reliability Based Control (RBC) field trial, pending an approved NERC BAL (Resource and Demand Balancing) standard for the same measure of compliance.

OR UE 296
ICNU 0065

Date	PACW CPS2%	PACE CPS2%
Jan-12	63.29%	85.78%
Feb-12	60.95%	86.67%
Mar-12	64.57%	83.53%
Apr-12	60.98%	78.28%
May-12	57.61%	72.62%
Jun-12	53.20%	68.33%
Jul-12	57.58%	70.07%
Aug-12	64.99%	71.87%
Sep-12	64.58%	78.31%
Oct-12	61.63%	74.69%
Nov-12	65.35%	70.61%
Dec-12	69.82%	66.51%
Jan-13	58.94%	64.22%
Feb-13	58.91%	65.55%
Mar-13	52.70%	64.02%
Apr-13	52.70%	63.06%
May-13	58.38%	61.79%
Jun-13	65.16%	60.17%
Jul-13	68.06%	62.96%
Aug-13	68.32%	66.89%
Sep-13	69.86%	62.85%
Oct-13	72.54%	64.30%
Nov-13	70.19%	71.27%
Dec-13	70.71%	66.12%
Jan-14	70.71%	59.72%
Feb-14	65.97%	58.76%
Mar-14	60.61%	53.26%
Apr-14	57.98%	59.20%
May-14	65.04%	64.04%
Jun-14	54.04%	51.15%
Jul-14	60.23%	57.84%
Aug-14	63.39%	56.80%
Sep-14	65.85%	59.73%
Oct-14	61.41%	57.54%
Nov-14	40.16%	39.91%
Dec-14	45.01%	49.56%

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 296

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
2016 Transition Adjustment Mechanism.	)
	)
______________________________________	)

REDACTED EXHIBIT ICNU/104

CALCULATION OF EIM INTER-REGIONAL DISPATCH SHAPE

June 29, 2015

Exhibit ICNU/104 is confidential pursuant to Protective Order No. 10-069 and has been redacted in its entirety.